

**STAFF'S PRELIMINARY
FORECAST OF NATURAL GAS
PRODUCTION AND WELLHEAD PRICES**

Assumptions and Results

for the
1997 FUELS REPORT
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INTRODUCTION

Staff is presently preparing a natural gas price and supply forecast in support of the **1997 Fuels Report**. This document explains the major assumptions and data sources underlying Staff's preliminary forecast of natural gas production and wellhead prices. Distribution of the California end-use price forecast will be delayed until mid-April, in order to incorporate: 1) anticipated decisions in the El Paso General Rate Case Settlement and the Southern California Gas Company (SoCalGas) Biennial Cost Allocation (BCAP) proceedings, and 2) Pacific Gas and Electric Company's (PG&E) BCAP Application filed at the CPUC in early March. Inclusion of critical information from these filings will clearly improve the accuracy of any end-use price forecast.

As has been the case since 1989, the North American Regional Gas (NARG) model is the principal tool used by the Commission to generate production and wellhead price estimates. The NARG model is a generalized equilibrium model that simultaneously solves for supply, demand and price equilibrium for 19 North American supply and demand regions over a 45-year time horizon. California is divided into four demand regions: the Pacific Gas and Electric Company (PG&E), the Southern California Gas Company (SoCalGas), the San Diego Gas and Electric Company (SDG&E), and the enhanced oil recovery (EOR) regions. Details of the NARG model methodology, structure and operating characteristics are discussed in the **1995 Natural Gas Market Outlook**, publication number P300-95-017A, available from the Commission's Publications Office.

A new capability now included in the code of the NARG model is the model's ability to account for reserve growth (or reserve appreciation) over time. The model allows the user to input a certain growth percentage estimate for each resource cost curve in the model that reflects the rate at which proved reserves and undiscovered resources grow over time. Staff's work to date suggests that these growth rates have a dramatic effect on both prices and production.

The addition of the reserve appreciation parameter fundamentally changes the economics of the NARG model. Previously, the model assumed ultimate depletion of natural gas resources, an assumption derived from Hotelling resource exhaustability theory. The new version of the model, while still based on Hotelling economics, minimizes the depletion effects.

Given the potential impact that reserve appreciation can have on NARG-related price and supply forecasts, the next section addresses Staff's resource assumptions exclusively. Specific attention will focus on reserve appreciation. Other assumptions and data input sources that underlie the preliminary forecast are addressed in Section II. Section III briefly discusses the resulting production and wellhead price projections for U.S. and Canadian regions. The final section provides information about an upcoming Staff workshop to discuss the forecast and procedures for filing comments.

I. RESOURCE ESTIMATES AND RESERVE APPRECIATION

For the second consecutive *Fuels Report*, Staff performed a comprehensive reassessment of the resource cost curves during the development of Staff's preliminary basecase forecast. A complete set of cost curves used in the analysis is provided in Attachment A. The resource estimates were discussed extensively in a *1997 Fuels Report* hearing held on August 13, 1996.

The current NARG database includes 88 active resource cost curves in the continental U.S., Alaska, and Canada. For this *Fuels Report* cycle, Staff's work has focused on cost curves in the Lower 48. Canadian cost curves were left unchanged except that the capital and operating costs were adjusted from 1993 to 1995 dollars. Alaska curves remain identical to those used in the last forecast.

Staff significantly enhanced the level of detail associated with the resource assumptions in the Lower 48. With respect to conventional resources, Staff increased the number of curves from 21 in the *1995 Natural Gas Market Outlook* work to 38. The new curves coincide with the provinces outlined by the US Geological Survey (USGS) and the Minerals Management Service (MMS) in their respective 1995 National Assessments.

Equally important are the changes made to the unconventional resource base. Perhaps the greatest change in the structure of the resource cost curve database applies to coalbed methane potential. In the past, Staff included any coalbed methane resources outside the San Juan Basin in the conventional resource database. Responding to our commitment to carefully investigate the outlook for coalbed methane production in the *1997 Fuels Report*, the database now includes 17 coalbed methane cost curves across eight distinct supply regions.

Changes were also made to refine the estimate of tight sands resources. The present report contains 13 tight sands cost curves in six regions. Tight gas resource potential in the Permian and Anadarko basins assumed in the 1995 report has been eliminated, based on USGS assumptions that those resources are contained in deep conventional formations. In addition, the NARG database now includes six cost curves that treat Devonian shale from the Appalachian supply basins and Antrim shale in the Michigan Basin.

The basis for the resource cost curves is the USGS *1995 National Assessment of United States Oil and Gas Resources*. Federal offshore estimates of resource potential are based on MMS' *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*. Staff is indebted to the Staff of both agencies for their willingness to respond to the countless requests for data during the past year.

Different from past reports, resource cost curves in the NARG model no longer distinguish between resource potential in shallow and deep formations. Staff aggregated estimates from both formations due to the lack of proved reserve data by depth.

A. Proved Reserves

Staff estimates approximately 152 TCF of proved reserves were in the Lower 48 at the end of 1993. Approximately 40 percent of the total was located in the Gulf Coast, with another 19 percent in the Anadarko region. The estimates shown are based on EIA figures provided in its *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1994 Annual Report*. EIA's estimate is approximately 10 TCF higher than the

Staff estimate, due to Staff's use of proved reserve data from the Alaska Department of Natural Resources and the California Department of Conservation.

Table 1 disaggregates proved reserve estimates by producing basin and resource type. Approximately three-quarters (114 TCF) of the total is found in conventional formations, with the Gulf Coast and Anadarko regions containing the largest shares. Approximately 38 TCF of the reserves are located in unconventional formations among seven major supply regions. The San Juan and the Rocky Mountain basins dominate the amount of unconventional reserves in inventory in the Lower 48.

TABLE 1 PROVED RESERVE ESTIMATE BY SUPPLY REGION (YEAR-END 1993) Trillions of Cubic Feet					
	Conventional	Coalbed Methane	Tight Sands	Shale	Total
Anadarko	27.977	0.110	0.000	0.000	28.087
Appalachia	0.236	0.810	4.580	1.380	7.006
California	4.613	0.000	0.000	0.000	4.613
Gulf Coast	55.348	1.237	2.978	0.000	59.563
North Central	0.993	0.000	0.000	1.010	2.003
Northern Great Plains	2.149	0.000	0.000	0.000	2.149
Permian	14.343	0.000	0.000	0.000	14.343
Rocky Mountains	4.898	0.240	9.891	0.000	15.029
Pacific Northwest	0.028	0.000	0.000	0.000	0.028
San Juan	3.150	7.820	7.660	0.000	18.630
Total - US Lower 48	113.735	10.217	25.109	2.390	151.451

The unconventional estimates are based on work performed by Advanced Resources International (ARI) in support of the USGS assessment. For additional information, see the ARI series of articles on unconventional resources published in December 1995 and January 1996 in *Oil and Gas Journal*² and testimony provided at the August 1996 hearing. Staff's unconventional resource estimate is approximately seven TCF below that of ARI; however, the difference is included as part of conventional proved reserve estimate, consistent with the geologic plays provided to Staff by USGS.

B. Potential Resources

Staff assumes 625 TCF of resources potentially available from undiscovered formations. The estimates are based on data provided by USGS and MMS. Staff estimates 274 TCF of potential resources in conventional formations with another 350 TCF of unconventional resources in the Lower 48. The Gulf Coast contains the largest share of conventional resources with the Rocky Mountains maintaining the largest share of unconventional potential resources. A summary of resource potential by basin and resource type appears in Table 2.

¹ For more information, see California Department of Conservation, *1994 Annual Report of the State Oil and Gas Supervisor*; and Alaska Department of Natural Resources, *Historical and Projected Oil & Gas Consumption*, 2/94 for reserves and 3/95 for production.

² See the following Oil & Gas Journal articles: 1) *How Unconventional Gas Prospers Without Tax Incentives*, 12/11/95, p. 76-81, 2) *Technology Spurs Growth of U.S. Coalbed Methane*, 1/1/96, p.56-62 3) *New Basins Invigorate U.S. Gas Shales Play*, 1/22/96, p.53-58, and 4) *Tight Sands Gain as a U.S. Gas Source*, 3/18/96, p. 102-107.

TABLE 2 POTENTIAL RESOURCE ESTIMATE Trillions of Cubic Feet					
Basin	Conventional	Coalbed Methane	Tight Gas	Shale	Total
Anadarko	18.127	5.008	0.000	0.000	23.135
Appalachia	2.389	14.309	27.145	25.876	69.719
California	18.920	0.000	0.000	0.000	18.920
Gulf Coast	186.052	2.308	5.770	0.000	194.130
North Central	3.227	1.611	0.000	19.293	24.131
Northern Great Plains	7.177	1.904	44.543	0.000	53.624
Permian	17.152	0.000	0.000	0.000	17.152
Rocky Mountains	18.249	16.349	134.256	0.000	168.854
Pacific Northwest	1.140	0.698	12.091	0.000	13.929
San Juan	2.040	17.807	21.737	0.000	41.584
Total - US Lower 48	274.473	59.994	245.542	45.169	625.178

C. Reserve Appreciation

A new resource category being considered by Staff for the first time is proved reserve appreciation. Proved reserve appreciation is defined as the additional resource expected to be added to reserves due to extension of known fields, reserve revisions, and improved recovery techniques.³ To properly account for this estimate in NARG, Staff reviewed reserve appreciation estimates with USGS and MMS Staff and spent considerable time reviewing reserve data available from EIA and other sources.

A first order review of the data suggests a wide variation of reserve growth depending on the year being considered. Consider the average reserve growth percentage for the Rocky Mountains between 1989 and 1995. During that period, the average growth rate was 6.3 percent but the range was from -3.0 percent in 1990 to 12.1 percent in 1995⁴.

Wide variations are also apparent between producing basins. Compared to the relatively “immature” producing region of the Rocky Mountains, the more “mature” San Juan Basin exhibited reserve growth at 1.3 percent per year between 1989 and 1995. The range in reserve growth across all basins in the Lower 48 during the same period varied between -1.7 percent per year for California offshore to 6.9 percent in the Appalachian region.⁵

Staff’s preliminary work confirms that the price and supply estimates produced by the NARG model are extremely sensitive to the assumed level of reserve appreciation. Staff is genuinely interested in obtaining comments from industry and 1997 Fuels Report participants about appropriate reserve appreciation estimates to use as model inputs. In the interim, a series of reserve appreciation reference cases has been developed for consideration. The assumptions for each case follow. Results using the various cases will be discussed in Section III of this report.

Case 1: USGS High Annual Growth Rate Case

³ Source: *1995 National Assessment of United States Oil and Gas Resources*, U.S. Geological Survey Circular 1118, pages 4-5.

⁴ Source: *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, Annual Reports from 1989-1995.

⁵ Ibid.

USGS estimates 175 TCF of reserve appreciation from conventional reserves between 1993 and the year 2015, representing an average 5.15 percent growth rate on an annual basis for the entire Lower 48. Escalation rates used by Staff for individual producing basins in the NARG model vary based on the location of the reserves, ranging from 2.7 percent in the San Juan Basin to 5.5 percent in the Permian Basin (see Table 3). MMS projects 33 TCF of reserve growth in Gulf Coast offshore waters between 1995 and 2020, a 3.3 percent annual growth rate. No rate of escalation was applied to California offshore cost curves due to environmental concerns restricting the viability of future offshore drilling activity.

Data were not available to Staff for developing proved reserve appreciation percentages for Lower 48 unconventional and Canadian resources. Staff applied a generic three percent per year escalation factor to all unconventional curves. A one percent growth rate was applied to all Canadian curves. These percentages were used because the model generated prices which are reasonably consistent with near-term market conditions. Staff requests specific information on reserve growth from these regions in order to improve the accuracy the NARG model inputs.

Using the above percentages, approximately 331 TCF of proved reserve appreciation occurs in the case. Of the total, 250 TCF is attributed to conventional onshore reserves, 36 TCF to conventional offshore reserves, and 46 TCF to unconventional reserves.

Case 2: USGS Low Annual Growth Rate Case

USGS estimates 132 TCF of conventional reserve appreciation between 1993 and the year 2015, representing a average growth rate of 1.97 percent for the Lower 48.⁶ Escalation rates used by Staff range from 1.1 percent for East Coast production areas to 2.2 percent for the Pacific Northwest. Since MMS did not provide a reserve growth estimate beyond 2020, Staff applied the same reserve growth rate calculated by USGS for Gulf Coast onshore regions to the Gulf offshore regions. No rate of escalation was applied to the California offshore cost curves.

Staff again applied a three percent per year escalation factor to all unconventional curves and one percent growth rate to all Canadian curves in this case.

Using the above percentages, approximately 124 TCF of proved reserve appreciation occurs in the case. Of the total, 59 TCF is attributed to conventional onshore reserves, 19 TCF to conventional offshore reserves, and 46 TCF to unconventional reserves.

Case 3: EIA 4.4% Annual Growth Rate Case

Staff substituted the USGS reserve growth estimates used in Cases 1 and 2 with estimates calculated using EIA's annual reports. In this case, Staff assumes a 4.4 percent average growth rate on an annual basis for the Lower 48. Escalation rates for individual producing regions range from 0.8 percent for the San Juan Basin to 6.6 percent for the Appalachian Basin. Staff maintained its three percent per year escalation factor for unconventional curves and one percent growth rate to all Canadian curves.

Through the year 2020, approximately 260 TCF of proved reserve appreciation occurs in this case. Of the total, 161 TCF is attributed to conventional onshore reserves, 53 TCF to conventional offshore reserves, and 46 TCF to unconventional reserves.

⁶ The 132 TCF estimate is derived using a USGS annual average growth rate of 1.97 percent for reserve appreciation from 1993 to 2015. Although the total reserve growth equals 308 TCF for the period between 1993 and 2071, Staff adjusted the USGS figure to provide a suitable comparison for the Low and High USGS cases.

Case 4: Two Percent Annual Growth Rate Case

Staff applied a generic two percent reserve growth assumption for all cost curves except the California offshore and Pacific Northwest conventional curves, which were set to zero. In this case, 104 TCF of conventional reserve appreciation is calculated by the NARG model between 1993 and the year 2020, the lowest total of all cases considered in this report. Of the total, 61 TCF is from conventional onshore reserves, 18 TCF from offshore reserves, and 24 TCF from unconventional reserves.

Case 5: Four Percent Annual Growth Rate Case

Staff also applied a generic four percent reserve growth assumption for all cost curves except the California offshore and Pacific Northwest conventional curves, which were set to zero. In this case, 276 TCF of conventional reserve appreciation is calculated by the NARG model between 1993 and 2020, 159 TCF from conventional onshore reserves, 46 TCF from offshore reserves, and 71 TCF from unconventional reserves.

Table 3 compares the reserve appreciation percentages assumed by Staff for each of the five cases.

TABLE 3 PROVED RESERVE APPRECIATION PERCENTAGE COMPARISON (Annual Growth Rate per Year)						
		1 High USGS	2 Low USGS	3 EIA 4.4%	4 Two Pct	5 Four Pct
Conventional Cost Curves						
Anadarko		5.23	1.91	4.08	2.00	4.00
Appalachia		2.90	1.09	6.63	2.00	4.00
California	Onshore	6.59	2.16	1.42	2.00	4.00
	Offshore	0.00	0.00	0.00	0.00	0.00
Gulf	Onshore - Eastern Gulf/Black Warrior	5.20	2.09	2.46	2.00	4.00
	Onshore - All Others	5.20	2.09	2.80	2.00	4.00
	Offshore - State	5.20	2.09	4.39	2.00	4.00
	Offshore - Federal	3.31	2.09	4.39	2.00	4.00
North Central		2.90	1.09	6.19	2.00	4.00
Northern Great Plains		5.43	2.00	3.94	2.00	4.00
Pacific Northwest		0.00	0.00	0.00	0.00	0.00
Permian		5.52	2.01	5.50	2.00	4.00
Rocky Mountains	Uinta-Piceance, Paradox, Snake River	2.73	1.62	6.12	2.00	4.00
	All Others	4.17	2.00	6.12	2.00	4.00
San Juan	San Juan Basin, Southwest Desert	2.73	1.62	0.84	2.00	4.00
	Raton Basin	5.43	2.00	0.84	2.00	4.00
Unconventional	Tight Sands, Coalbed Methane, Shale	3.00	3.00	3.00	2.00	4.00
Canadian Cost Curves	All	1.00	1.00	1.00	2.00	4.00
Notes:						
1. Cases 1 and 2 estimates were based on <i>1995 USGS National Assessment of United States Oil and Gas Resources</i> . USGS provided growth rates by region. Estimates were then allocated to each basin based on the basin's location.						
2. Case 3: Staff reviewed EIA reserve growth estimates by state for the 1989-95 period. The statewide data was then aggregated into producing regions based on Staff's understanding of the location of each producing region in the model.						
3. Cases 4 and 5: Two and four percent were arbitrarily selected to produce a lower an upper bound for the sensitivity cases. California production set to zero, reflecting a environmental concerns restricting the viability of future offshore drilling activity.						

Reserve Appreciation Summary

Table 4 summarizes the amount of reserve appreciation by producing basin for each of the five cases described above. Case 1 (High USGS Case) produces the largest level of reserve appreciation (331 TCF) with Case 4 (Two Percent Case) the lowest level (104 TCF). The widest variations in reserve growth are apparent in regions with the largest levels of proved reserves, specifically the Gulf Coast, Anadarko, and Permian basins.

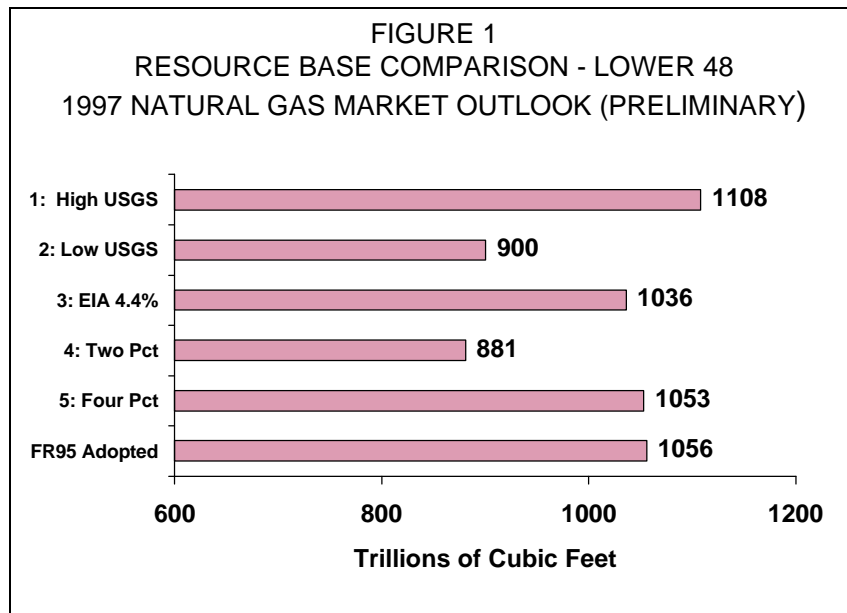
TABLE 4 PROVED RESERVE APPRECIATION ESTIMATES TO 2020 Trillions of Cubic Feet					
	Case 1	Case 2	Case 3	Case 4	Case 5
	High USGS	Low USGS	EIA 4.4%	2 Percent	4 Percent
Anadarko	82.998	18.786	54.535	19.854	52.898
Appalachia	8.542	8.348	9.369	4.952	13.195
California	13.235	2.245	1.334	2.033	5.417
Gulf Coast	123.815	44.704	87.266	40.378	106.514
North Central	2.388	1.571	5.265	1.416	3.772
Northern Great Plains	6.807	1.519	3.946	1.519	4.047
Permian	46.893	10.204	46.605	10.139	27.013
Rocky Mountains	24.460	15.568	31.820	10.624	28.305
Pacific Northwest	0.000	0.000	0.000	0.000	0.000
San Juan	22.268	20.617	19.702	13.169	35.087
Total	331.406	123.563	259.842	104.085	276.248

Please note that the estimates represent the amount of reserve appreciation expected by the year 2020. The volume of reserve appreciation shown in Table 4 would be considerably higher if Staff included reserve appreciation expected beyond the year 2020. This fact alone suggests that the reserve estimates provided in the analysis are conservative.

Another feature now contained in the NARG model is the ability to allow potential, undiscovered resources to grow over time. The feature operates in exactly the same manner as the proved reserve appreciation feature, driven by a percentage growth assumption entered for each resource cost curve. Given that growth in undiscovered resources has been driven historically by the discovery of unconventional resource types, Staff set annual potential reserve appreciation to zero percent for all cost curves in the model.

D. Natural Gas Resource Summary and Comparison

Staff's estimate of total resource availability (proved reserves plus potential reserves plus reserve appreciation) depends upon the reserve appreciation reference case considered. At the low end of the resource estimate is Case 4 (Two Percent Reserve Appreciation) at 881 TCF, including only 104 TCF of reserve appreciation through the year 2020. The highest resource estimate is part of Case 1 (High USGS Case), which contains 1108 TCF of proved and potential natural gas resources. As illustrated in Figure 1, only Case 1 exceeds the resource estimate assumed in the *1995 Natural Gas Market Outlook*.



E. Technology Impact on Costs for Potential Resources

The methodology employed to develop technology impact parameters for the 1993 and 1995 *Natural Gas Market Outlooks* was retained for this preliminary forecast. Attachment B shows the potential impact each new technology is expected to have on drilling costs for each resource type. The last column of Attachment B represents the assumed lower bound for the potential reduction (percent) in capital costs used in the NARG model. Please note that Staff reduced the lower bound by an additional 20 percent to account for cost reductions due to new technologies not yet in place. Drilling costs to develop reserves are assumed to drop at an annual rate of 10 percent of the remaining potential reduction.

The primary source of drilling data used in the Staff technology assessment came from the American Petroleum Institute's *Joint Association Survey on 1994 Drilling Costs*, published in November 1995. The 20 percent future technology reduction was based on recommendations provided by Gas Research Institute Staff at a May 1996 meeting of the NARG User Group.

II. MODEL INPUTS AND ENHANCEMENTS

Considerable work was also performed by Staff beyond the scope of resource cost curves described in Section I. Structural enhancements as well as assumptions about initial conditions, demand projections, and other areas of interest are described in this section.

Structural Enhancements to the NARG Model

Several changes were made to the NARG model to better reflect the natural gas transportation network in North America. The most significant change centered on disaggregating the West North Central/Mountain (WNC/Mtn) demand region. The region was split in order to improve Staff analysis of natural gas flow and price projections throughout the western United States. Other changes include “rolling in” the costs of the PGT Original and Expansion pipelines, the creation of a Pacific Northwest demand region, the inclusion of Mexican demand in the base case, and improved corridor representation for gas flowing to the northeast. A brief description of each change follows.

■ Disaggregation of the WNC/Mtn Region into Three Regions

1. **Southwest Desert Demand Region** - new region in the model comprising Arizona, New Mexico, and Southern Nevada. This region better represents natural gas flows on the El Paso and Transwestern systems from the San Juan and Permian Basins. Included for the first time are direct links to demand centers in Arizona, New Mexico, and Las Vegas.
2. **Rocky Mountain Demand Region** - new region in the model including Colorado, Wyoming, Utah, Idaho, and Montana. Within the region itself are four separate demand nodes for each state, Colorado and Wyoming being combined. Staff completed this change to more accurately estimate market competition between producers in the Rocky Mountains and Canada.
3. **West North Central Demand Region** - including Kansas, Nebraska, North Dakota, South Dakota, Minnesota, Iowa, and Missouri. Capacity refinements were also made to the pipeline corridors linking the modified region with the Rocky Mountains, Anadarko, and East North Central (ENC) regions. Additionally, the link between the Anadarko and ENC sectors was eliminated to more accurately reflect flows from the Permian/Anadarko Basins to the midwest and allow competition with Rocky Mountain gas.

■ Addition of Pacific Northwest Demand Region - In conjunction with some of the work disaggregating the WNC/Mtn region, Staff added a new demand region comprising Washington, Oregon, and Northern Nevada. A Reno citygate was also created with new links representing the Paiute and Tuscarora Pipelines. The breakdown of Southern and Northern Nevada was based on review of pipeline-specific flow data from EIA and discussions with Southwest Gas Corporation, the primary distribution utility in Southern Nevada and owner of Paiute Pipeline in Northern Nevada.

■ Pacific Gas Transmission - The PGT original and expansion lines have been combined into one pipeline link, with a transmission rate equal to \$0.263 per decatherm. The rate was adopted by the FERC in mid-1996 in accepting a Settlement Agreement in PGT’s 1994 general rate case proceeding (RP94-149). Between 1996 and 2001, shippers holding firm capacity on the original PGT line (primarily PG&E) pay 75 percent of the rolled-in rate, while expansion shippers pay approximately 125 percent of the rate. Given the long-term nature of the model, Staff does not distinguish between the two rates in 1999, the first forecast period.

- Mexican Demand - The current case marks the first time Staff has included natural gas demand from Mexico in the base case. Demand projections are limited to Mexican provinces along the international border, based on the assumption that southern regions will continue to be served by government-run PEMEX.
- Eastern Canada Links - Recognizing the development of natural gas fields off of Nova Scotia and increased demand for gas in New England, Staff added a link between Eastern Canada and New England.
- Miscellaneous Pipeline Corridor Enhancements
 - New link from Raton Basin to Anadarko Region was added to account for Colorado Interstate Gas Company capacity from Northeastern New Mexico.
 - Link between East South Central to Mid-Atlantic region was eliminated to better represent interstate pipeline capacity along the eastern seaboard.

Initial Conditions

To generate a gas price forecast, the NARG model requires a set of initial conditions which balance demand with supply for the specified start or "base" year. In the present forecast, gas flows during 1994 are input to the model as an equilibrium of balanced natural gas flows at each point in the model structure.

The entire energy balance was performed in-house by Commission Staff. The California portion of the energy balance was compiled from several sources, primarily the *1994 California Gas Report*. Demand data for non-utility EOR cogeneration capacity were based on the Department of Conservation, Division of Oil and Gas publication, *80th Annual Report of the State Oil & Gas Supervisor*. The Commission's *Quarterly Fuel and Energy Report (QFER Form 10A)* provided data for California gas production transported directly to industrial and enhanced oil recovery facilities. Submittals to the Commission under the Petroleum Industry Information Reporting Act contain data for EOR steaming and oil burn.

For the rest of the Lower 48, Staff relied heavily on workpapers supporting EIA's *1994 Natural Gas Annual* report.

The workpapers contain information on natural gas flows across state and international boundaries identified by specific pipelines. Pipeline flows were then aggregated and assigned to individual transportation links or corridors in the NARG model. To determine the proper level of base year gas production, Staff used EIA's *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves 1994* report and a series of articles submitted by Advanced Resources International (ARI) to *Oil & Gas Journal* and testimony provided to the Commission at the August 1996 Resource Evaluation Hearing.⁷

The data provided by EIA contain information on a statewide basis, with some disaggregation in Texas, Louisiana, California, Oklahoma, and New Mexico. Other areas required some method of allocating statewide production to the various producing basins. To translate statewide production into production estimates for the Arkoma, Anadarko, Gulf Coast, Northern Great Plains, Permian, Rockies, and San Juan regions, Staff utilized 1993 production estimates by county for the following states: Arkansas, Colorado, Montana, Oklahoma, Texas, and Wyoming. The data were prepared by Dwight's Energy Services and furnished to Staff by EIA.

As an example, the state of Wyoming has 22 counties, 13 located in the Northern Great Plains supply region and nine in the Rocky Mountains supply region. Comparing county production for 1993, Staff determined that 86.5 percent of the total occurred in counties defined to be part of the Rocky Mountain supply region. Thus, that percentage of production in Wyoming was applied to base year Rocky Mountain estimates.

⁷ See Footnote 2.

The Canadian portion of the energy balance was done using several publications. *Gas Utilities - 1994*, published by Statistics Canada provided information on base year demand and gas flows between provinces. The data were converted from thousand cubic meters to billion cubic feet and split between core and noncore demand markets. Direct sales reported in the publication were allocated equally to core and noncore nodes. Staff kept the level of switchable fuel oil at base year 1992 levels. Provincial production estimates were obtained from *Gas Facts - 1994*, published by the American Gas Association, and discussions with CERI and NEB Staff. Pipeline flows in and out of Alberta were obtained from an Oil & Gas Journal article reporting shipments on the NOVA system.⁸

⁸ See Oil and Gas Journal, *NOVA Gas Shipments Climb*, 2/19/96, p.22.

Natural Gas Demand Projections

Staff relied on a variety of sources to generate a natural gas demand forecast. California natural gas demand projections were performed by Commission Staff in support of the *1996 Electricity Report*. Residential, commercial and industrial customer demand assumptions were developed by the Commission's Demand Analysis Office. The Electricity Resource Assessment Office derived UEG and cogeneration demand estimates using electric generation capacity expansion plan results.⁹ The demand data for 1994 represent actual consumption and were obtained from the California energy balance of gas production and consumption. Attachment C lists the demand for natural gas in the core market and the demand for natural gas plus competing oil in the noncore market for each demand region in California.

For all other regions in the continental United States, Staff utilized Gas Research Institute's (GRI) *Baseline Projection Data Book*, 1996 edition. Data were aggregated into core (non-switchable) and noncore (switchable) demand. Core demand with respect to the GRI data includes residential gas, commercial gas, natural gas vehicles (NGV) and 50 percent of industrial gas demand. Noncore demand includes the remaining 50 percent of industrial gas, all UEG and all cogeneration gas. It was assumed that natural gas can compete with oil in UEG and portions of industrial and commercial petroleum demand. Therefore, noncore projections also include UEG oil, 25 percent of commercial oil, and an increasing percentage of industrial oil (20 percent in 1999, 30 percent in 2004, 40 percent in 2009 and 50 percent in 2014 through 2039).

Staff derived the Canadian natural gas demand estimate using Canadian Gas Association's *Forecast of Domestic Natural Gas Demand: 1996-2010*. Forecasted data were provided by customer class for the six major Canadian provinces for the years 1995-1997, 2000, 2005, and 2010. Staff interpolated estimates for 1999, 2004, and 2009. Estimates from 2011-2019 were calculated based on the annual growth rate in demand from 1995 to 2010. Demand estimates beyond 2019 were assumed to increase at a constant one percent per year.

Staff placed 100 percent of residential and commercial requirements and 75 percent of industrial requirements for each Canadian demand region in the core sector. The remaining 25 percent of industrial demand and all electric generation requirements were allocated to noncore demand. These percentages were based on discussions with NEB representatives. Switchable fuel oil for industrial, electric generation, and petrochemical customers was also added to the noncore demand estimate, based on the Canadian Energy Research Institute's (CERI) *North American Natural Gas Outlook: Basin-on-Basin Competition* published in March 1996.

Mexican demand estimates were limited to three regions in Mexico located adjacent to the U.S. border (Baja, North, and East). Staff increased existing demand at an arbitrary one percent per year from recorded 1995 estimates. Using information provided by the EIA in its *Natural Gas Imports and Exports* report published in the second quarter of 1995, Staff identified new facilities expected to consume natural gas during the forecast period. Demand at these new facilities was increased at one percent per year after the project startup date. Finally, development of a Mexican natural gas market infrastructure enables Mexican production to satisfy 20 percent of requirements in the North and Eastern demand regions by 2019. Core and noncore distinctions were not addressed in this forecast.

Pipeline Transmission Rates and Discounting

Updated transportation rates for the pipeline corridors considered in the NARG model are provided in Attachment D. The rates used for the various corridors in the *1995 Natural Gas Market Outlook* are provided for comparison. When comparing current rates to rates used in previous reports, please note that the definition of some of the pipeline corridors may have changed due to structural enhancements. For example,

⁹ The UEG/cogeneration forecast does not include changes regarding how the restructured electricity market will operate. Absent large investments in new or existing generation facilities, generation sources are unlikely to change much in the short-run. In the long-run, ERAO does not expect much new generation being added until 2006, with large additions occurring outside California.

the WNC to ENC corridor (without Northern Border) in the present forecast is \$0.143 per MCF, \$0.45 per MCF less than the price used in the *1995 Natural Gas Market Outlook* forecast. The difference can be attributed to NARG structural enhancements. The WNC-ENC corridor no longer includes pipelines transporting gas out of the Rockies supply region. Instead, these pipelines are now accounted for in the Rockies-WNC corridor.

Average pipeline transportation rates for the corridors in the model were based on conversations with pipeline representatives or rates published in pipeline tariff booklets. A constant base tariff is assumed for all pipeline corridors throughout the forecast horizon. However, similar to the *1995 Natural Gas Market Outlook* forecast, the actual rate may vary based on the utilization of the pipeline corridor. The rate multipliers or discounts used in the analysis are shown in Table 5. For pipelines with utilization rates at or above 85 percent, no discount is applied to the rate. Below 85 percent, the discount increases, up to a maximum of 50 percent. Multipliers are also attached to pipeline corridors that exceed 115 percent of full capacity availability. The maximum multiplier is four times the base tariff, which occurs when utilization is double the initial capacity assumption.

<p style="text-align: center;">TABLE 5 UTILIZATION RATE MULTIPLIER USED IN THE NARG MODEL TO DETERMINE DISCOUNTS AND ADDERS (As Percent of the As-Billed Rate)</p>		
	Utilization Rate percent (%)	Standard Multiplier
Discounted Portion of Curve	0-50	0.500
	65	0.650
	75	0.800
	85	1.000
	100	1.000
Adder Portion of Curve	115	1.000
	120	1.250
	130	1.594
	140	1.938
	150	2.281
	160	2.625
	170	2.969
	200+	4.000

Pipeline Capacities

Staff updated pipeline corridor capacities in the NARG model using a variety of sources. From EIA, Staff used two publications, *Capacity and Service on the Interstate Natural Gas Pipeline System - 1990* (1992), *Natural Gas Annual - 1994*, and *Energy Policy Act: Interim Report on Natural Gas Flows and Rates* (1995). EIA also provided Staff with workpapers exhibiting capacities and flows across state borders by pipeline in computer spreadsheet format.

Staff also relied heavily on the work of Foster Associates in its December 1994 study entitled *Competitive Profile of Natural Gas Services*, various *FERC Form 567* 1993 and 1994 filings, and pipeline company bulletin boards. Canadian pipeline capacities were adjusted based on capacities published by the AGA in its September 1994 *Gas Energy Review* and conversations with various pipeline representatives.

Owner/Producer Discounts

The "Owner's Discount Rate" is defined as "the rate used by the original owner of a resource deposit to discount cash flows resulting from the sale of leases to resource producers." Conversely, the "Producer's Discount Rate" is the required rate of return on equity for all investments. In the *1995 Fuels Report* proceeding, Staff used six percent for both discount rates. Towards the end of the *1995 Fuels Report* proceeding, Dale Nesbitt, principal developer of the NARG model, was retained as an expert economic witness to testify at a July 1995 committee hearing. He argued that Staff should use a 10 percent owner's discount rate and four percent producer's discount rate. Although unable to incorporate his comments into the *1995 Natural Gas Market Outlook* forecast, Staff adopted these recommendations as well as his recommended 2.5 percent cost of debt for the current analysis.

Time Frame

The *1997 Natural Gas Market Outlook* gas price forecast uses 1994 as the base year. The NARG model generates forecast data in five-year increments starting from the 1994 base and ending with 2039. Although a 45-year forecast is generated, Staff focuses on the 1999 to 2019 forecast period.

Dollars

All prices in this analysis are in constant 1995 dollars. The deflator series used for this conversion was developed for the *1996 Electricity Report* based on Gross Domestic Product.

Exogenous Fuel Prices

Several fuel price forecasts are exogenous inputs to the model.

- Oil Price Forecast - The Commission's *Delphi VIII Survey of Oil Price Forecasts*¹⁰ is the source for the update of oil prices in the preliminary forecast. These oil prices are shown in Table 6 and were used for U.S. and Canadian oil price updates. The oil prices are lower than the *Delphi VII Survey of Oil Price Forecasts* used in the *1995 Natural Gas Market Outlook*.

TABLE 6 DELPHI VIII SURVEY OF OIL PRICES		
Year	Dollars per Barrel (1995\$)	Dollars per MCF (1995\$)
1994	15.40	2.73
1999	17.71	3.14
2004	18.84	3.35
2009	19.79	3.51
2014	20.53	3.65
2019	21.50	3.82
2024	22.66	4.02
2029	23.88	4.24
2034	25.17	4.47
2039	26.53	4.71
Source: California Energy Commission, <i>Results of the Delphi VIII Survey of Oil Price Forecasts</i> , P300-95-017B, March 1996		
Conversion formula Used Above: \$/Barrel/5.8 MMBtu/Barrel * 1.03 MCF/MMBtu.		

The oil price forecast is used to determine the regional price of residual fuel oil or heavy fuel oil that competes with natural gas in the noncore market sector. The conversion from the input Delphi world oil price to regional fuel oil price is achieved through a multiplier that has been determined for each region, based on historical prices of fuel oil consumed in each region. In the model, this price is assumed to be representative for all noncore customers including the industrial and electricity generation sectors.

- Backstop Price - The backstop price represents a price at which some technological breakthrough provides an unlimited supply of natural gas. Staff retained a constant \$5.00 per MCF backstop price for the entire forecast period.

¹⁰ Since 1982, the Commission has conducted biennial surveys of oil price forecasts using a modified Delphi approach. Under this method, a panel of recognized energy experts is selected and surveyed for their most likely, high, and low oil price forecasts considering contributions of numerous potential influences.

- Liquefied Natural Gas (LNG) Facilities and Prices - The NARG model includes four LNG regasification facilities in the U.S., three along the Atlantic seaboard and one on the Gulf coast. For the forecast period, it is assumed that no new facilities are added in the U.S. for importing LNG.

III. RESULTS

This section presents Staff's preliminary forecast of natural gas production and prices by region for North America over the 20-year forecast horizon (1999-2019), with 1994 as the base year. The first part of the section includes the "Base Case" results, which represents Staff's preferred estimate of production and prices.

Given the sensitivity of the NARG model to changes in proved reserve appreciation, this section also presents several sensitivity cases with different proved reserve appreciation assumptions. All other assumptions in the model remain the same for each case. Staff selected the EIA 4.4% reserve appreciation case (Case 3 on Page 6) as the Base Case because: 1) reserve growth estimates are based on actual recorded data (1989 to 1995), and 2) results of the case lie approximately mid-range between all the cases tested by Staff during the development of the forecast.

A. Base Case

Wellhead Prices and Production

In the Lower 48, natural gas production is expected to grow from 17.1 TCF recorded in 1994 to 18.9 in 1999, the first forecast year (Table 7). Between 1999 and 2019, Lower 48 production is expected to grow by 1.7 percent per year, reaching 26.7 TCF by the end of the forecast period. While also exhibiting positive growth, Canadian production will grow at a slower pace (one percent per year through the year 2019) compared to the percentage increase projected for the Lower 48.

Regional breakdowns of production are also provided in Table 7. Natural gas produced in the Gulf Coast region continues to account for approximately half of Lower 48 production throughout the 1999-2019 forecast period. Rocky Mountain production emerges as the second largest source of natural gas in the Lower 48, surpassing combined production from the Permian and Anadarko Basins by the year 2014. Staff anticipates the strong growth in production in the Rocky Mountains to be driven by conventional production in the Wyoming Thrust Belt and tight sands production in the Greater Green River Basin.

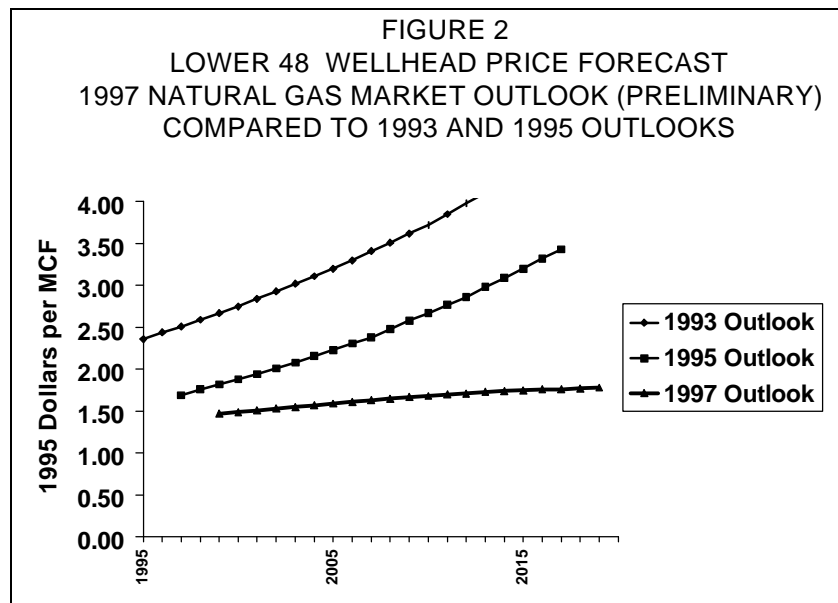
In Canada, Alberta producers continues to provide the bulk of Canadian production even though strong growth on a percentage basis will be the case for British Columbia producers. Canadian production for all regions increases by 1.7 TCF from 1994 to 2019, with most of the additional supplies meeting new domestic demand. Canadian exports are expected to peak in 2014 at 3.1 TCF.

TABLE 7 LOWER 48 AND CANADIAN PRODUCTION (TCF PER YEAR)						
1997 Preliminary Base Case						
Producing Region	1994	1999	2004	2009	2014	2019
LOWER 48						
Anadarko	2.890	2.620	2.396	2.091	2.014	1.709
Appalachia	0.531	0.669	1.125	1.184	1.377	1.543
California	0.311	0.366	0.350	0.397	0.414	0.422
Gulf Coast	9.135	9.709	10.839	11.895	12.714	13.590
North Central	0.186	0.515	0.600	0.652	0.684	0.714
Northern Great Plains	0.200	0.264	0.293	0.319	0.338	0.352
Pacific Northwest	0.003	0.009	0.013	0.026	0.047	0.065
Permian	1.677	1.814	1.910	1.928	1.813	1.772
Rocky Mountains	1.121	1.555	1.941	2.751	3.828	4.656
San Juan	1.075	1.380	1.812	1.819	1.874	1.892
Total: Lower 48	17.129	18.901	21.279	23.061	25.102	26.715
CANADA						
Alberta	4.064	4.592	4.906	5.278	5.595	5.754
British Columbia	0.569	0.726	0.860	0.859	0.871	0.975
Eastern Canada	0.000	0.000	0.000	0.000	0.000	0.003
Saskatchewan	0.282	0.263	0.173	0.124	0.097	0.085
Total: Canada	4.885	5.580	5.939	6.262	6.563	6.817

A comparison of natural gas prices by region and in the aggregate is shown in Table 8. For the Lower 48, the average price increases from \$1.46 per MCF in 1999 to \$1.78 per MCF in 2019, an increase of one percent per year (in 1995 dollars) on an average annual basis. The growth rate is considerably lower than previous Commission estimates, which have consistently been in the range of 3-4 percent (see Figure 2 for comparison). The sharp decline in the growth is due to two factors: 1) the use of reserve appreciation in the model for the first time, and 2) the change in the owner/producer's discount rates.

Canadian wellhead prices escalate at a rate of 1.9 percent per year during the forecast period. The higher rate of increase compared to the Lower 48 is partially due to the lack of information available on reserve appreciation in Canada. In the absence of actual data on reserve appreciation, an arbitrary one percent per year reserve growth estimate was incorporated for all Canadian resources.

TABLE 8 LOWER 48 AND CANADIAN WELLHEAD PRICES (1995\$ PER MCF)					
1997 Preliminary Base Case					
Producing Region	1999	2004	2009	2014	2019
LOWER 48					
Anadarko	1.53	1.70	1.85	1.95	2.05
Appalachia	2.02	2.08	2.26	2.34	2.38
California	1.69	1.85	2.00	2.18	2.34
Gulf Coast	1.49	1.62	1.74	1.83	1.88
North Central	1.72	1.76	1.81	1.85	1.87
Northern Great Plains	1.10	1.12	1.16	1.19	1.21
Pacific Northwest	1.59	1.75	1.89	2.03	2.20
Permian	1.38	1.50	1.63	1.76	1.84
Rocky Mountains	1.14	1.14	1.17	1.21	1.23
San Juan	1.22	1.30	1.42	1.50	1.59
Total: Lower 48	1.46	1.57	1.67	1.74	1.78
CANADA					
Alberta	1.04	1.16	1.28	1.39	1.54
British Columbia	1.07	1.20	1.36	1.54	1.70
Eastern Canada	N/A	N/A	N/A	N/A	2.22
Saskatchewan	1.53	1.84	2.00	2.17	2.34
Total: Canada	1.07	1.18	1.30	1.42	1.57



Staff believes that some reserve/resource appreciation is already embedded in the unchanged Canadian resource cost curves (as used in the previous forecast). Comments on this issue are requested from parties in order to incorporate additional data into a revised forecast to be released later this year.

Natural Gas Supplies and Prices at the California Border

Natural gas produced in the Southwest is expected to remain the principal source of supply for California consumers during the next 20 years, accounting for nearly half of total statewide requirements. After a decline from 1.013 TCF in the 1994 base year to 0.892 TCF in 1999, Southwest supplies to California will increase two percent per year to 1.327 TCF in 2019. Much of this increase can be attributed to new demand in the Baja region of Northern Mexico, which will have its gas delivered through California.

Remaining statewide natural gas requirements will be met by Canadian, Rocky Mountain, and in-state producers. Canadian deliveries to California will satisfy about one-quarter of total demand, with California and Rocky Mountain producers sharing the remainder.

Regarding estimates of border prices at Malin, Topock, or Wheeler Ridge, Staff expects prices to increase 1.6 percent per year from \$1.60 per MCF in 1999 to \$2.19 per MCF in the year 2019. Specific estimates of supplies and prices available to California by region appear in Table 9.

TABLE 9 CALIFORNIA BORDER SUPPLY AVAILABILITY AND PRICE						
1997 Preliminary Base Case						
Producing Region	1994	1999	2004	2009	2014	2019
Production (TCF):						
California	0.311	0.366	0.350	0.397	0.414	0.422
Southwest	1.013	0.892	1.148	1.168	1.255	1.327
Rocky Mountains	0.243	0.184	0.253	0.330	0.352	0.372
Canada	0.590	0.619	0.654	0.681	0.718	0.744
Total Supply Available to California	2.157	2.061	2.404	2.576	2.739	2.865
Price (1995\$/MCF)						
California	N/A	1.69	1.85	2.00	2.18	2.34
Southwest	N/A	1.64	1.77	1.93	2.08	2.23
Rocky Mountains	N/A	1.73	1.83	1.94	2.10	2.25
Canada	N/A	1.46	1.58	1.72	1.86	2.00
Average Price at California Border	N/A	1.60	1.74	1.89	2.04	2.19

B. Sensitivity Cases

As mentioned earlier, the NARG model is highly sensitive to changes in reserve appreciation estimates. The cases considered in this section were described in Part C of Section I of this report: 1) Low USGS Reserve Appreciation (Case 1); 2) High USGS Reserve Appreciation (Case 2); 3) Two Percent Reserve Appreciation (Case 4); and 4) Four Percent Reserve Appreciation (Case 5). The EIA 4.4% Reserve Appreciation Case (Case 3) is considered the Base Case.

Table 10 compares Lower 48 wellhead price projections for the Base Case and the four sensitivity cases. A series of charts and graphs comparing the five cases are included in Attachment E.

TABLE 10 LOWER 48 WELLHEAD PRICE COMPARISON (1995\$ PER MCF)
--

1997 Preliminary Base Case vs. Sensitivity Cases						
	1999	2004	2009	2014	2019	AGR *
Base Case	1.46	1.57	1.67	1.74	1.78	1.0%
Sensitivity Cases						
Low USGS Reserve Appreciation	1.83	2.02	2.19	2.33	2.45	1.5%
High USGS Reserve Appreciation	1.34	1.43	1.53	1.60	1.66	1.1%
Two Percent Reserve Appreciation	1.92	2.14	2.36	2.53	2.70	1.7%
Four Percent Reserve Appreciation	1.36	1.46	1.55	1.63	1.67	1.0%
* AGR equals the annual growth rate calculated over the 1999-2019 forecast period.						

IV. NEXT STEPS

Staff will hold a workshop to discuss the natural gas price and supply forecast on May 14, 1997. The meeting will be held in Hearing Room B at the California Energy Commission in Sacramento. In preparation for that meeting, Staff is requesting comments or suggestions about the forecast from interested parties.

Your comments will be accepted in any format you would like. Please contact the following people if you have any questions about the forecast:

Jairam Gopal (916) 654-4880 jgopal@energy.state.ca.us
Scott Tomashefsky (916) 654-4896 stomashe@energy.state.ca.us

If you wish to mail your comments, please do so to either of the above people by May 5 at the following address:

California Energy Commission
Fuel Resources Office
1516 Ninth Street, MS-23
Sacramento, CA 95814

**STAFF'S PRELIMINARY
FORECAST OF NATURAL GAS
PRODUCTION AND WELLHEAD PRICES**

Attachments

for the
1997 FUELS REPORT
DOCKET NO. 96-FR-1

Prepared by
Fuel Resources Office
Energy Information and Analysis Division
California Energy Commission
April 10, 1997

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ATTACHMENT	DESCRIPTION
A	Resource Cost Curves
B	Technology Impacts
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D	Pipeline Transport Rates and Capacities
E	Charts and Graphs Comparing Base Case and Sensitivity Cases

Disclaimer: The views and conclusions in this document are those of the Staff of the Fuel Resources Office and should not be interpreted as necessarily representing the policies of either the California Energy Commission or the state of California.

ATTACHMENT A

CEC Resource Cost Curve Definitions

Conventional Resources

Basin	USGS or MMS Province	Description
Anadarko	USGS 53 and 59 USGS 55-56 USGS 58 USGS 60-62	Central Kansas Nehama Uplift Anadarko Basin Arkoma Basin
Appalachian	USGS 67 USGS 68-69	Appalachian Basin Blue Ridge Thrust Belt/Piedmont
California	USGS 7-9 USGS 10-14 Onshore USGS 10-14 Offshore MMS Offshore	Northern California Onshore Southern California Onshore Southern California State Offshore Federal Offshore
Gulf Coast	USGS 47 Onshore USGS 47 Offshore USGS 48-50 Onshore USGS 48-50 Offshore USGS 65 USGS 84 USGS 85 MMS Offshore	Western Gulf Onshore Western Gulf State Offshore Eastern Gulf Onshore Eastern Gulf State Offshore Black Warrior Basin Western Gulf Onshore - High H ₂ S Content Eastern Gulf Onshore - High H ₂ S Content Federal Offshore
North Central	USGS 63 USGS 64 and 66	Michigan Basin Illinois Basin & Cincinnati Arch
Northern Great Plains	USGS 27-29 USGS 31 and 51 USGS 33-34 USGS 35	Central/Southwestern Montana Williston Basin Powder River Basin Wind River Basin
Permian	USGS 44 and 46 USGS 45	Permian Basin and Marathon Thrust Belt Fort Worth Basin
Pacific Northwest	USGS 4-5	Oregon - Washington
Rocky Mountains	USGS 17-19 USGS 20 USGS 21 USGS 36 USGS 37 USGS 38-39 USGS 81 USGS 83	Great Basin Uinta-Piceance Basin Paradox Basin Wyoming Thrust Belt Southwestern Wyoming Denver Basin Paradox Basin - High H ₂ S Content Southwestern Wyoming - High H ₂ S Content
San Juan	USGS 22-23 USGS 24-25 USGS 40-41	San Juan Basin Arizona-New Mexico Raton Basin

CEC Resource Cost Curve Definitions - Continued

Coalbed Methane

Basin	Plays	Description
Anadarko	USGS 5650 USGS 6050 USGS 6250-6251	Forest City - Central Basin Cherokee Platform - Central Basin Arkoma Basin
Appalachian	USGS 6750-6751 USGS 6752 USGS 6753	Northern Appalachian Central Appalachian Cahaba Field
Gulf Coast	USGS 6550-6553	Black Warrior Basin
North Central	USGS 6450	Illinois - Central Basin
Northern Great Plains	USGS 3350-3351 USGS 3550	Powder River Basin Wind River Basin
Pacific Northwest	USGS 450-452	Western Oregon-Washington
Rocky Mountains	USGS 2050-2052 USGS 2053-2056 USGS 3750-3755	Uinta Basin Piceance Basin Southwestern Wyoming
San Juan	USGS 2250 USGS 2252-2253 USGS 4150-4152	San Juan Overpressured San Juan Underpressured Raton Basin

Tight Gas

Basin	Plays	Description
Appalachian	USGS 6728-6730	Clinton-Medina
Gulf Coast	USGS 4923	Cotton Valley
Northern Great Plains	USGS 2810-2812 USGS 3113	North Central Montana - Biogenic Williston Basin
Rocky Mountains	USGS 2007 USGS 2010 USGS 2015-2020 USGS 3740-3744 USGS 3906	Piceance Basin - Mesaverde Williams Fork Piceance Basin - Mesaverde Iles Uinta Basin Greater Green River Basin Denver Basin
Pacific Northwest	USGS 503	Eastern Oregon-Washington
San Juan	USGS 2205 USGS 2209 USGS 2211	Dakota Central Basin Central Basin Mesaverde Pictured Cliffs

CEC Resource Cost Curve Definitions - Continued

Shale

Basin	USGS Plays	Description
Appalachian	USGS 6733-6735	Upper Devonian Sandstone
	USGS 6740-6741	Devonian Shale
	USGS 6742	Devonian Shale - Lower Maturity
North Central	USGS 6319-6320	Michigan Basin - Antrim Shale
	USGS 6407	New Albany
	USGS 6604	Cincinnati Arch - Devonian Black Shale

Canadian Cost Curves

Basin	CEC Designation	Description
Alberta	A	Alberta Foothill Region
	B	South Central Region
	C	Frontier Region
	D	Coalbed Methane
British Columbia	A	Conventional Sources
	B	Coalbed Methane Sources
Eastern Canada	A	Conventional Sources
Northern Canada	Onshore	Conventional Sources
	Offshore	Conventional Sources
Saskatchewan	A	Conventional Sources

RESOURCE COST CURVES - CONVENTIONAL

Anadarko USGS 53 & 59 - Central Kansas		
Proved Reserves 0.000 TCF R/P Ratio 9.2 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.15	0.69
0.150	0.25	0.86
0.417	0.60	1.44
0.533	2.00	1.45
0.555	2.50	2.00
0.578	3.00	2.50

Anadarko USGS 55 to 56 - Nehama Uplift		
Proved Reserves 0.000 TCF R/P Ratio 9.2 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.11	0.55
0.182	0.24	0.86
0.290	0.37	1.09
0.395	1.35	1.76
0.434	3.45	2.96

Anadarko USGS 58 - Anadarko Basin		
Proved Reserves 24.105 TCF R/P Ratio 9.4 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.06	0.39
2.823	0.13	0.53
5.067	0.17	0.61
7.230	0.25	0.84
9.509	0.38	1.01
11.223	0.86	1.38
12.375	1.69	2.28
13.478	3.92	3.05

Anadarko USGS 60 to 62 - Arkoma Basin		
Proved Reserves 3.872 TCF R/P Ratio 7.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.06	0.39
0.588	0.10	0.58
1.634	0.17	0.62
2.127	0.21	0.85
2.584	0.33	1.02
3.023	0.55	1.19
3.278	0.99	1.75
3.501	1.94	2.78
3.637	3.01	3.19

Appalachia USGS 67 - Appalachian Basin		
Proved Reserves 0.236 TCF R/P Ratio 35.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.06	0.36
0.332	0.14	0.57
1.248	0.25	0.98
1.726	0.54	1.44
1.890	1.13	2.12
1.974	2.33	3.10

Appalachia USGS 68 to 69 - Blue Ridge Thrust Belt		
Proved Reserves 0.000 TCF R/P Ratio 35.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.06	0.36
0.222	0.14	0.56
0.337	0.23	0.96
0.405	0.93	1.75
0.411	1.40	2.29
0.415	2.37	3.05

California USGS 7 to 9 - Northern CA Onshore		
Proved Reserves 0.498 TCF R/P Ratio 5.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.07	0.50
0.112	0.09	0.55
0.418	0.16	0.72
1.185	0.21	0.81
1.756	0.27	0.91
2.595	0.38	1.10
3.044	0.61	1.37
3.436	0.98	1.81
3.631	1.13	1.87
3.860	1.62	1.90
4.045	3.70	1.98
4.102	5.76	2.71

California USGS 10 to 14 - Southern CA Onshore		
Proved Reserves 2.876 TCF R/P Ratio 11.4 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.08	0.52
0.088	0.10	0.57
0.237	0.14	0.63
0.796	0.21	0.81
1.469	0.30	0.99
2.337	0.51	1.29
3.235	1.13	2.03
3.462	1.76	2.53
3.623	2.70	3.24
3.723	3.04	3.49

California USGS 10 to 14 - Southern CA Offshore State Waters		
Proved Reserves 0.266 TCF R/P Ratio 35.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.22	0.64
0.295	0.37	0.64
0.853	0.83	1.20
0.910	0.89	1.26
0.992	0.95	1.38
1.147	2.09	1.89
1.295	4.17	2.60

California USGS 10 to 14 - Southern CA Offshore Federal Waters		
Proved Reserves 1.471 TCF R/P Ratio 28.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.22	0.64
2.231	0.37	0.64
6.456	0.83	1.20
6.888	0.89	1.26
7.504	0.95	1.38
8.676	2.09	1.89
9.800	4.17	2.60

Gulf Coast USGS 47 - Western Gulf Onshore		
Proved Reserves 17.542 TCF R/P Ratio 5.7 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.02	0.34
8.862	0.07	0.43
19.970	0.15	0.56
43.081	0.45	0.58
46.935	0.65	0.69
50.222	1.07	0.77
53.422	1.92	0.81
54.647	2.90	0.91
55.829	5.35	1.30
56.552	9.25	2.67

Gulf Coast USGS 47 - Western Gulf Offshore State Waters		
Proved Reserves 0.335 TCF R/P Ratio 4.6 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.18	0.45
0.618	0.30	0.53
2.714	0.53	1.01
4.749	0.92	1.06
5.777	1.23	1.17
6.643	2.09	1.88
6.962	3.40	2.61
7.305	6.13	3.98

Gulf Coast USGS 48 to 50 - Eastern Gulf Onshore		
Proved Reserves 8.778 TCF R/P Ratio 9.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.02	0.41
5.190	0.16	0.43
9.721	0.31	0.54
13.205	0.66	0.75
14.527	1.08	0.82
15.578	1.62	1.06
17.971	4.59	1.93

Gulf Coast USGS 48 to 50 - Eastern Gulf Offshore State Waters		
Proved Reserves 0.917 TCF R/P Ratio 6.4 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.30	0.99
0.182	0.70	1.04
0.488	0.95	1.15
0.586	1.55	1.84
0.653	2.67	3.87

Gulf Coast USGS 65 - Black Warrior Basin		
Proved Reserves 1.732 TCF R/P Ratio 13.5 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.13	0.57
0.392	0.21	0.70
0.846	0.36	0.93
1.271	0.71	1.39
1.829	2.89	1.57
1.944	3.77	3.33

Gulf Coast USGS 84 - Western Gulf Onshore High Sulfur Content		
Proved Reserves 0.000 TCF R/P Ratio 5.7 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.19	0.40
0.559	0.53	0.58
0.838	0.77	0.68
1.175	1.85	0.96
1.266	3.29	1.02
1.367	5.00	3.45

Gulf Coast USGS 85 - Eastern Gulf Onshore High Sulfur Content		
Proved Reserves 0.000 TCF R/P Ratio 9.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.05	0.37
0.508	0.16	0.53
1.649	0.30	0.71
2.946	0.64	1.09
3.645	1.03	1.46
3.821	1.57	1.82
4.560	4.26	3.13

Gulf Coast Federal Waters		
Proved Reserves 26.044 TCF R/P Ratio 5.5 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.18	0.45
8.091	0.30	0.53
35.559	0.53	1.01
62.212	0.92	1.06
75.677	1.23	1.17
87.028	2.09	1.88
91.203	3.40	2.61
95.700	6.13	3.98

North Central USGS 63 - Michigan Basin		
Proved Reserves 0.993 TCF R/P Ratio 16.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.07	0.64
0.253	0.10	0.76
0.734	0.17	1.01
1.815	0.32	1.40
2.119	0.56	1.78
2.506	1.28	2.67
2.762	5.76	2.97

North Central USGS 64 & 66 - Illinois Basin		
Proved Reserves 0.000 TCF R/P Ratio 16.9 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.05	0.57
0.078	0.08	0.65
0.204	0.14	0.99
0.339	0.30	1.33
0.389	0.53	1.80
0.423	1.01	2.00
0.436	1.55	2.54
0.485	2.60	3.41

Northern Great Plains USGS 27 to 29 - Central/SW Montana		
Proved Reserves		0.278 TCF
R/P Ratio		13.7 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.06	0.31
0.657	0.09	0.40
1.167	0.15	0.48
1.640	0.25	0.75
2.159	0.33	0.95
2.594	0.51	1.00
2.854	0.90	1.48
3.022	1.79	2.24
3.092	3.36	3.27

Northern Great Plains USGS 31 & 51 - Williston Basin		
Proved Reserves		0.373 TCF
R/P Ratio		13.7 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.05	0.36
0.384	0.37	0.54
0.752	0.72	0.67
1.086	1.14	0.85
1.442	2.98	1.35
1.695	4.70	1.75

Northern Great Plains USGS 33 to 34 - Powder River Basin		
Proved Reserves		0.659 TCF
R/P Ratio		14.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.17	0.73
0.534	0.28	0.80
1.050	0.53	1.04
1.683	1.94	1.12
1.790	2.95	1.43
1.899	4.71	1.91

Northern Great Plains USGS 35 - Wind River Basin		
Proved Reserves		0.839 TCF
R/P Ratio		14.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.11	0.49
0.141	0.24	0.75
0.277	0.42	1.06
0.399	0.64	1.21
0.453	1.65	2.20
0.491	3.27	3.17

Permian USGS 44 & 46 - Permian Basin		
Proved Reserves		14.343 TCF
R/P Ratio		8.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.03	0.34
1.608	0.09	0.42
4.278	0.15	0.49
7.746	0.21	0.60
9.783	0.29	0.74
11.662	0.48	0.98
13.989	1.59	1.00
14.500	2.43	1.30
14.882	3.90	1.75
15.230	4.80	1.76

Permian USGS 45 - Fort Worth Basin		
Proved Reserves		0.000 TCF
R/P Ratio		8.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.10	0.52
0.248	0.14	0.61
0.741	0.18	0.69
1.386	0.24	0.79
1.559	0.60	1.36
1.887	1.33	2.14
1.922	2.34	2.91

Rocky Mountains USGS 17 to 19 - Great Basin		
Proved Reserves		0.000 TCF
R/P Ratio		10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.09	0.43
0.099	0.27	1.01
0.206	0.66	1.32
0.254	1.39	1.98
0.291	2.14	2.57
0.308	3.46	3.39
0.332	3.69	3.43

Rocky Mountains USGS 20 - Uinta/Piceance Basin		
Proved Reserves		1.135 TCF
R/P Ratio		10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.13	0.72
1.715	0.27	0.98
2.574	0.38	1.16
2.888	0.49	1.25
3.220	0.65	1.58
3.700	1.08	1.89
3.924	1.64	2.27
3.996	3.32	2.30

Rocky Mountains USGS 21 - Paradox Basin		
Proved Reserves		0.000 TCF
R/P Ratio		10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.10	0.60
0.220	0.18	0.75
0.589	0.30	0.99
0.949	0.59	1.34
1.222	1.15	1.95
1.329	1.76	2.46
1.472	2.95	3.29

Rocky Mountains USGS 36 - Wyoming Thrust Belt		
Proved Reserves		2.677 TCF
R/P Ratio		10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.11	0.51
3.415	0.18	0.60
7.015	0.30	0.77
8.567	0.51	1.02
9.065	0.68	1.24
9.704	2.52	1.30
9.815	3.74	1.63
10.015	5.79	2.11

Rocky Mountains USGS 37 - Southwestern Wyoming		
Proved Reserves		0.395 TCF
R/P Ratio		10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.11	0.59
0.071	0.15	0.76
0.236	0.24	0.85
0.300	0.31	0.98
0.468	0.62	1.32
0.526	0.86	1.58
0.582	1.23	1.96
0.629	1.87	2.52
0.708	3.20	3.33

Rocky Mountains USGS 38 to 39 - Denver Basin		
Proved Reserves		0.194 TCF
R/P Ratio		10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.05	0.71
0.369	0.10	1.06
0.577	0.22	1.40
0.627	0.38	2.00
0.672	0.85	2.57
0.703	1.25	3.42

Rocky Mountains USGS 81 - Paradox Basin High Sulfur Content		
Proved Reserves 0.000 TCF R/P Ratio 10.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.19	0.67
0.055	0.30	0.87
0.091	0.40	0.98
0.152	0.78	1.51
0.183	1.00	1.71
0.254	3.00	1.91
0.262	5.21	2.00
0.270	8.08	2.57

Rocky Mountains USGS 83 - Southwestern Wyoming High Sulfur Content		
Proved Reserves 0.000 TCF R/P Ratio 10.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.16	0.59
0.147	0.25	0.74
0.244	0.31	0.84
0.358	0.41	0.99
0.480	0.70	1.41
0.562	1.05	1.61
0.643	2.09	2.43
0.753	3.19	3.16

Pacific Northwest USGS 4 to 5 - Oregon/Washington		
Proved Reserves 0.028 TCF R/P Ratio 8.8 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.10	0.53
0.038	0.13	0.59
0.195	0.25	0.85
0.422	0.37	1.11
0.687	0.83	1.54
0.736	1.13	1.72
0.903	4.31	1.97
1.140	7.68	2.76

San Juan USGS 22 to 23 - San Juan Basin		
Proved Reserves 3.150 TCF R/P Ratio 35.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.14	0.27
0.205	0.26	0.53
0.520	0.34	0.65
0.796	0.63	1.00
0.975	0.98	1.19
1.078	1.59	1.95
1.131	3.31	2.69
1.179	6.05	3.74

San Juan USGS 24 to 25 - Arizona/New Mexico		
Proved Reserves 0.000 TCF R/P Ratio 35.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.10	0.36
0.053	0.14	0.42
0.163	0.22	0.57
0.223	0.29	0.70
0.256	0.39	0.84
0.286	0.80	1.27
0.292	1.13	1.57
0.302	1.69	2.09
0.321	4.88	3.81

San Juan USGS 40 to 41 - Raton Basin		
Proved Reserves 0.000 TCF R/P Ratio 35.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.11	0.53
0.044	0.14	0.55
0.386	0.21	0.74
0.510	0.46	1.11
0.535	1.18	1.98
0.540	2.25	2.90

RESOURCE COST CURVES - COALBED METHANE

Anadarko USGS 5650 - Forest City (Central Basin)				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	1.18	0.71	0.066	0
0.197	1.44	0.91	0.092	1
0.300	2.28	1.54	0.100	2
0.375	3.00	2.19	0.093	3
0.443	6.00	3.49	0.082	4
			0.071	5
			0.036	10
			0.021	15
			0.014	20
			0.010	24

Anadarko USGS 6050 - Cherokee Platform (Central Basin)				
Proved Reserves 0.070 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.44	0.50	0.034	0
0.636	0.55	0.59	0.036	1
1.100	0.94	0.89	0.046	2
1.400	1.68	1.46	0.056	3
1.600	3.13	2.59	0.062	4
1.890	6.00	4.33	0.063	5
			0.048	10
			0.034	15
			0.026	20
			0.021	24

Anadarko USGS 6250 to 6251 - Arkoma Basin				
Proved Reserves 0.040 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.26	0.60	0.097	0
0.275	0.36	0.82	0.070	1
1.180	0.62	1.37	0.065	2
2.133	1.18	2.39	0.061	3
2.675	3.41	3.78	0.057	4
			0.053	5
			0.039	10
			0.029	15
			0.023	20
			0.020	24

Appalachia USGS 6750 to 6751 - Northern Appalachia				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.30	0.61	0.033	0
1.643	0.42	0.96	0.060	1
8.686	0.96	1.04	0.071	2
10.831	1.78	1.87	0.075	3
11.710	3.79	4.84	0.072	4
			0.067	5
			0.044	10
			0.020	20
			0.016	24

Appalachia USGS 6752 - Central Appalachia				
Proved Reserves 0.810 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.26	0.34	0.196	0
0.549	0.34	0.41	0.143	1
1.777	0.51	0.61	0.098	2
2.190	2.00	1.02	0.074	3
2.309	3.87	2.48	0.059	4
			0.049	5
			0.026	10
			0.017	15
			0.013	20
			0.010	24

Appalachia USGS 6753 - Canhaba Field				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.53	0.35	0.038	0
0.133	0.71	0.49	0.029	1
0.179	1.09	0.79	0.030	2
0.249	1.84	1.37	0.037	3
0.274	3.31	2.50	0.043	4
0.290	6.17	4.29	0.047	5
			0.048	6
			0.049	7
			0.049	9
			0.048	10
			0.041	15
			0.034	20
			0.030	24

Gulf Coast				
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USGS 6550 to 6553 - Black Warrior Basin				
Proved Reserves 1.237 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.44	0.56	0.056	0
0.090	0.54	0.68	0.104	1
1.276	0.83	0.71	0.113	2
2.015	1.44	1.41	0.098	3
2.226	3.28	2.57	0.082	4
2.308	5.97	3.52	0.069	5
			0.058	6
			0.050	7
			0.044	8
			0.038	9
			0.034	10
			0.021	15
			0.014	20
			0.011	24

North Central USGS 6450 - Illinois-Central Basin				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.75	1.02	0.061	0
0.800	1.16	1.44	0.087	1
1.200	2.14	2.36	0.096	2
1.611	6.00	5.22	0.092	3
			0.083	4
			0.072	5
			0.036	10
			0.015	20
			0.011	24

Northern Great Plains USGS 3350 to 3351 - Powder River Basin				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.25	0.35	0.320	0
0.295	0.39	0.43	0.255	1
0.349	0.66	0.59	0.135	2
0.914	1.19	0.91	0.080	3
1.349	2.24	1.54	0.051	4
1.475	4.32	2.71	0.035	5
			0.009	10
			0.004	15
			0.002	20
			0.001	24

Northern Great Plains USGS 3550 - Wind River Basin				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.25	0.35	0.081	0
0.211	0.33	0.38	0.075	1
0.336	1.19	0.91	0.084	2
0.375	2.71	2.05	0.081	3
0.429	4.32	2.71	0.073	4
			0.065	5
			0.038	10
			0.025	15
			0.017	20
			0.013	24

Pacific Northwest USGS 450 to 452 - Western Oregon/Washington				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.47	0.35	0.061	0
0.203	0.52	0.38	0.043	1
0.463	1.23	0.57	0.040	2
0.489	1.42	0.90	0.036	3
0.590	2.12	1.00	0.034	4
0.675	3.76	1.61	0.034	5
0.698	5.51	2.62	0.040	10
			0.041	15
			0.040	20
			0.039	24

Rocky Mountains USGS 2050 to 2052 - Uinta Basin				
Proved Reserves 0.240 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.20	0.46	0.042	0
1.724	0.34	0.51	0.042	1
3.442	0.62	0.70	0.048	2
3.509	0.72	0.83	0.055	3
3.720	1.03	0.91	0.059	4
4.353	1.48	1.28	0.061	5
4.794	2.61	2.18	0.060	6
4.908	5.14	3.95	0.058	7
			0.055	8
			0.052	9
			0.049	10
			0.043	12
			0.036	15
			0.028	20
			0.027	21
			0.026	22
			0.025	23
			0.023	24

Rocky Mountains USGS 2053 to 2056 - Piceance Basin				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.18	0.43	0.061	0
2.261	0.23	0.46	0.050	1
4.696	0.38	0.50	0.052	2
6.191	0.56	0.61	0.054	3
6.404	0.69	0.70	0.053	4
6.863	0.96	0.85	0.052	5
7.200	1.22	0.96	0.050	6
7.602	5.28	3.82	0.048	7
			0.046	8
			0.044	9
			0.042	10
			0.034	15
			0.029	20
			0.026	24

Rocky Mountains USGS 3750 to 3755- Southwestern Wyoming				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.16	0.42	0.048	0
0.272	0.20	0.44	0.048	1
0.744	0.26	0.49	0.048	2
1.576	0.50	0.58	0.048	3
1.738	0.56	0.65	0.048	4
2.223	0.73	0.79	0.048	5
2.997	1.28	0.94	0.044	14
3.376	2.12	1.23	0.034	15
3.676	2.71	2.10	0.024	17
3.839	5.24	3.83	0.020	20
			0.017	24

San Juan USGS 2250 - San Juan Basin Overpressured				
Proved Reserves 3.910 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.06	0.21	0.050	0
3.363	0.29	0.35	0.050	1
4.899	0.55	0.52	0.050	2
6.390	1.08	0.84	0.050	3
7.988	2.10	1.46	0.070	4
8.771	4.13	2.69	0.079	5
			0.069	6
			0.062	7
			0.056	8
			0.052	9
			0.048	10
			0.035	15
			0.028	20
			0.024	24

San Juan USGS 2252 to 2253 - San Juan Basin Underpressured				
Proved Reserves 3.910 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.17	0.24	0.081	0
3.545	0.26	0.30	0.075	1
4.466	0.46	0.42	0.084	2
5.854	1.59	1.11	0.081	3
6.387	3.07	1.93	0.073	4
7.230	5.27	3.22	0.065	5
			0.038	10
			0.025	15
			0.017	20
			0.013	24

San Juan USGS 4150 to 4152 - Raton Basin				
Proved Reserves 0.810 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.07	0.23	0.074	0
0.044	0.09	0.25	0.074	1
0.832	0.17	0.30	0.074	2
1.384	0.31	0.42	0.074	3
1.510	1.15	1.03	0.068	4
1.600	2.00	1.39	0.060	5
1.700	2.24	1.84	0.037	10
1.804	4.38	3.15	0.022	20
			0.019	24

RESOURCE COST CURVES - TIGHT SANDS

Appalachia USGS 6728 to 6730 - Clinton/Medina				
Proved Reserves 4.580 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.52	1.16	0.209	0
1.326	0.71	1.26	0.159	1
3.556	0.89	1.38	0.124	2
7.402	1.16	1.50	0.098	3
14.229	1.91	1.77	0.079	4
20.987	3.60	2.50	0.064	5
27.145	4.34	2.97	0.053	6
			0.045	7
			0.038	8
			0.032	9
			0.028	10
			0.024	11
			0.021	12
			0.018	13

Gulf Coast USGS 4923 - Cotton Valley				
Proved Reserves 2.978 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.05	0.35	0.144	0
0.982	0.07	0.36	0.119	1
2.838	0.11	0.38	0.100	2
4.000	0.52	0.78	0.084	3
5.100	2.10	1.62	0.081	4
5.770	6.36	2.42	0.061	5
			0.030	6
			0.016	15
			0.009	20
			0.006	25
			0.005	27

Northern Great Plains USGS 2810 to 2812 - North Central Montana				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.08	0.41	0.076	0
2.375	0.13	0.50	0.069	1
8.756	0.22	0.74	0.063	2
13.877	0.41	1.12	0.058	3
25.559	0.80	1.22	0.053	4
32.746	0.99	1.35	0.049	5
37.524	1.35	1.65	0.033	10
41.177	2.29	1.94	0.023	15
42.754	4.22	3.52	0.015	20
			0.009	30
			0.007	35
			0.005	44

Northern Great Plains USGS 3113 - Williston Basin				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	1.67	1.16	0.083	0
1.043	1.90	1.80	0.075	1
1.532	2.57	2.80	0.068	2
1.732	3.75	3.25	0.062	3
1.789	6.59	3.52	0.057	4
			0.053	5
			0.049	6
			0.045	7
			0.042	8
			0.039	9
			0.037	10
			0.027	15
			0.021	20
			0.016	26

Pacific Northwest USGS 503 - Eastern Oregon/Washington				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	1.91	0.47	0.220	0
1.648	2.17	0.49	0.172	1
5.138	4.11	0.65	0.134	2
8.232	4.64	0.69	0.104	3
9.132	5.98	0.73	0.081	4
12.091	7.08	0.82	0.063	5
			0.049	6
			0.038	7
			0.030	8
			0.023	9
			0.018	10
			0.005	15
			0.004	16
			0.002	19

Rocky Mountains USGS 2007 - Piceance Basin (Mesaverde Williams Fork)				
Proved Reserves 0.994 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.61	0.73	0.220	0
1.287	0.73	0.79	0.171	1
3.700	1.14	0.85	0.133	2
4.000	1.95	1.16	0.104	3
4.300	3.64	1.62	0.081	4
4.774	6.93	2.00	0.063	5
			0.049	6
			0.038	7
			0.030	8
			0.023	9
			0.018	10
			0.014	11
			0.011	12
			0.009	13
			0.007	14
			0.005	15
			0.004	16
			0.003	17
			0.002	20

Rocky Mountains USGS 2010 - Piceance Basin (Mesaverde Iles)				
Proved Reserves 0.434 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.66	0.71	0.220	0
1.131	0.78	0.77	0.171	1
3.845	1.21	0.88	0.133	2
4.100	2.06	1.16	0.104	3
4.400	3.80	1.62	0.081	4
4.722	7.24	3.55	0.063	5
			0.049	6
			0.038	7
			0.030	8
			0.023	9
			0.018	10
			0.014	11
			0.011	12
			0.009	13
			0.007	14
			0.005	15
			0.004	16
			0.003	17
			0.002	20

Rocky Mountains USGS 2015 to 2020 - Uinta Basin				
Proved Reserves 0.434 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.08	0.49	0.120	0
0.246	0.11	0.56	0.106	1
0.291	0.13	0.58	0.093	2
0.607	0.18	0.61	0.082	3
0.965	0.21	0.76	0.072	4
1.506	0.36	0.80	0.064	5
2.022	0.60	1.05	0.056	6
2.228	0.79	1.08	0.050	7
2.847	1.14	1.11	0.044	8
2.920	1.17	1.27	0.039	9
3.298	1.59	1.75	0.030	11
3.505	1.79	1.75	0.018	15
5.050	2.74	1.75	0.010	20
5.920	4.86	3.21	0.005	25
6.803	7.36	3.32	0.002	34

Rocky Mountains USGS 3740 to 3744 - Greater Green River Basin				
Proved Reserves 6.162 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.21	0.42	0.217	0
1.059	0.24	0.44	0.170	1
1.134	0.31	0.52	0.133	2
3.161	0.46	0.67	0.104	3
11.716	0.64	0.69	0.081	4
15.043	0.74	0.77	0.064	5
27.759	1.00	0.80	0.050	6
35.006	1.11	1.01	0.039	7
40.459	1.41	1.06	0.031	8
53.262	1.65	1.12	0.024	9
74.129	2.46	1.15	0.019	10
91.876	3.00	1.46	0.015	11
99.912	4.05	1.68	0.011	12
107.616	5.39	1.89	0.009	13
117.140	8.49	2.10	0.007	14
			0.006	15
			0.004	16
			0.003	18
			0.002	20

Rocky Mountains USGS 3906 - Denver Basin				
Proved Reserves 2.301 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.28	1.03	0.123	0
0.512	0.40	1.51	0.103	1
0.726	0.68	2.35	0.087	2
0.796	1.24	2.97	0.075	3
0.815	4.86	5.98	0.064	5
			0.033	10
			0.019	15
			0.008	25
			0.002	43

San Juan USGS 2205 - Dakota Central Basin				
Proved Reserves 2.105 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.27	0.30	0.091	0
4.838	0.38	0.43	0.083	1
6.800	0.57	0.69	0.075	2
7.576	1.78	1.78	0.069	3
8.281	6.56	3.12	0.057	5
			0.036	10
			0.014	20
			0.009	25
			0.005	30
			0.003	35
			0.002	40

San Juan USGS 2209 - Central Basin Mesaverde				
Proved Reserves 4.592 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.07	0.20	0.074	0
3.016	0.25	0.22	0.069	1
4.511	0.50	0.25	0.064	2
6.858	1.00	0.32	0.059	3
8.287	1.50	0.48	0.051	5
9.160	2.00	1.22	0.035	10
9.327	3.01	2.37	0.016	20
			0.011	25
			0.008	30
			0.005	35
			0.004	49

San Juan USGS 2211 - Pictured Cliffs				
Proved Reserves 0.963 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.22	0.26	0.097	0
0.875	0.40	0.30	0.088	1
2.132	0.75	0.44	0.080	2
2.718	1.00	0.70	0.072	3
2.917	2.25	0.96	0.065	5
3.129	4.87	3.02	0.059	10
			0.023	20
			0.014	25
			0.009	30
			0.005	35

RESOURCE COST CURVES - SHALE

Appalachia USGS 6733 to 6735 - Upper Devonian Sandstone				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.97	1.70	0.407	0
2.740	1.48	1.99	0.211	1
5.172	2.40	2.07	0.125	2
7.373	3.82	2.56	0.082	3
10.378	5.87	2.60	0.057	4
12.781	7.68	2.75	0.041	5
			0.031	8

Appalachia USGS 6740 to 6741 - Devonian Shale				
Proved Reserves 1.380 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.14	0.59	0.052	0
0.880	0.19	0.70	0.049	1
3.981	0.21	0.85	0.046	2
6.293	0.55	1.88	0.043	3
7.748	1.54	2.24	0.040	4
8.900	2.32	3.71	0.038	5
9.785	4.52	5.71	0.029	10
			0.023	15
			0.019	20
			0.015	25
			0.013	30
			0.011	35
			0.010	40
			0.008	45
			0.008	49

Appalachia USGS 6742 - Devonian Shale (Lower Maturity)				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.71	1.58	0.097	0
1.690	1.02	2.78	0.085	1
2.716	1.97	3.48	0.075	2
3.310	5.21	5.32	0.066	3
			0.059	4
			0.054	5
			0.034	10
			0.024	15
			0.018	20
			0.014	25
			0.013	27

North Central USGS 6319 to 6320 - Michigan Basin (Antrim Shale)				
Proved Reserves 1.010 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.15	0.74	0.107	0
1.244	0.15	0.86	0.093	1
6.048	0.29	1.29	0.081	2
11.495	0.61	1.67	0.071	3
14.580	1.23	1.74	0.063	4
15.839	2.39	2.12	0.055	5
16.215	5.64	3.19	0.032	10
			0.020	15
			0.014	20
			0.010	25
			0.007	30
			0.006	34

North Central USGS 6407 - New Albany				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	0.87	1.17	0.082	0
0.408	1.01	1.71	0.075	1
0.904	1.70	2.21	0.069	2
1.392	2.22	3.96	0.063	3
1.772	6.69	6.16	0.058	4
			0.054	5
			0.038	10
			0.027	15
			0.021	20
			0.015	26

North Central USGS 6604 - Cincinnati Arch (Devonian Black Shale)				
Proved Reserves 0.000 TCF				
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)	Production Profile	Production Year
0.000	1.55	1.01	0.081	0
0.301	1.66	1.43	0.074	1
0.626	1.93	2.43	0.068	2
1.033	2.56	3.36	0.062	3
1.254	3.72	3.85	0.057	4
1.306	6.08	4.90	0.053	5
			0.053	10
			0.037	15
			0.027	20
			0.016	25
			0.014	27

RESOURCE COST CURVES - CANADA

British Columbia - A Conventional		
Proved Reserves 8.520 TCF R/P Ratio 10.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.019	0.477
0.970	0.019	0.477
2.480	0.028	0.477
4.620	0.038	0.485
8.340	0.094	0.501
8.940	0.189	0.548
11.530	0.283	0.563
13.200	0.472	0.579
16.030	0.567	0.610
19.790	0.709	0.657
22.530	0.850	0.706
27.860	0.992	0.729
29.870	1.180	0.779
31.510	1.416	0.839
32.930	1.889	0.839
33.740	2.361	1.201
34.150	2.833	1.649
35.000	3.305	2.027
36.000	3.778	3.578

British Columbia - B Coalbed Methane		
Proved Reserves 0.000 TCF R/P Ratio 20.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	1.133	0.469
2.000	1.322	0.548
4.000	1.700	0.784
6.000	1.983	1.059
7.000	2.361	1.649
8.000	3.778	2.240
8.500	4.722	2.830
9.000	5.667	3.224

Alberta - A Foothills Conventional		
Proved Reserves 28.490 TCF R/P Ratio 10.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.047	0.461
3.062	0.066	0.469
6.233	0.113	0.485
10.963	0.170	0.508
15.217	0.170	0.539
17.087	0.170	0.563
20.112	0.170	0.587
26.052	0.170	0.587
31.827	0.170	0.595
35.567	0.170	0.682
38.518	0.170	0.784
42.643	0.227	0.784
48.290	0.312	0.784
54.377	0.576	0.784
59.125	0.679	0.784
62.718	1.681	0.784
65.945	1.861	2.004
73.333	3.778	4.011

Alberta - B South Central Conventional		
Proved Reserves 20.240 TCF R/P Ratio 10.0 Years		
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.038	0.355
1.558	0.085	0.355
4.125	0.085	0.355
9.772	0.085	0.371
12.467	0.122	0.395
14.740	0.122	0.426
19.873	0.122	0.434
22.495	0.152	0.449
24.310	0.152	0.449
29.590	0.217	0.449
31.295	0.236	0.449
33.110	0.246	0.497
35.072	0.416	0.505
37.693	0.454	0.521
41.433	0.501	0.592
46.933	1.388	1.464
49.500	2.361	2.016
56.833	4.212	4.031

Alberta - C Frontier Conventional		
Proved Reserves R/P Ratio		9.000 TCF 10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.056	0.343
0.458	0.103	0.367
1.412	0.142	0.461
2.713	0.227	0.461
3.245	0.283	0.461
4.363	0.293	0.532
5.610	0.312	0.563
6.527	0.491	0.563
7.737	0.501	0.595
8.855	0.567	0.595
11.532	1.048	0.595
12.723	1.218	0.682
13.768	1.218	1.076
15.730	2.247	1.272
16.757	2.247	1.674
17.655	2.247	1.736
18.718	3.787	3.987
20.643	5.241	5.782
23.833	9.152	7.623

Alberta - D Coalbed Methane		
Proved Reserves R/P Ratio		0.000 TCF 20.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.178	0.303
2.369	0.178	0.376
13.965	0.230	0.408
14.968	0.303	0.408
22.662	0.418	0.470
27.000	0.784	0.617
31.000	1.045	0.679
34.000	2.613	0.805
38.000	4.181	1.286
41.000	6.272	4.181

Saskatchewan Conventional		
Proved Reserves R/P Ratio		3.140 TCF 10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.019	0.387
0.300	0.019	0.387
0.690	0.236	0.448
1.030	0.614	0.645
1.550	0.944	0.841
1.760	1.416	1.236
2.080	2.125	1.629
2.230	2.833	2.023
2.800	3.778	2.416
3.800	5.667	2.810

Northern Canada Onshore - Conventional		
Proved Reserves R/P Ratio		11.760 TCF 20.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.944	0.839
10.000	1.889	1.036
15.000	2.833	1.232
20.000	3.541	1.429
25.000	4.250	1.626
30.000	4.958	2.020
35.000	5.667	2.414
40.000	6.374	3.200

Northern Canada - Offshore Conventional		
Proved Reserves R/P Ratio		0.000 TCF 10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	1.322	0.525
8.000	1.463	0.567
15.000	1.917	0.567
20.000	4.722	3.778

Eastern Canada Conventional		
Proved Reserves R/P Ratio		11.760 TCF 10.0 Years
Cumulative Reserves (TCF)	Capital Cost (95\$/MCF)	Operating Cost (95\$/MCF)
0.000	0.897	0.367
2.360	0.897	0.367
2.930	0.897	0.367
4.000	1.227	0.540
6.000	1.416	0.563
8.200	2.361	1.232
10.000	3.778	3.200

ATTACHMENT B
Adjusted Drilling Cost Impacts for Gas Wells

		Unadjusted Percent Drilling Cost	Drilling Cost Reduction Factors				Adjusted Percent Drilling Cost	Percent Development Cost	Adjusted Total Capital Cost	Future Technology Factor	Adjusted Total Capital Cost
			3-D Seismic	Horizontal Drilling	Slim Hole Drilling	New Bits					
Appalachia	Conventional	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
	Coalbed	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
	Tight Sands	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
	Shale	39.4%	0.940	1.000	0.986	0.700	25.5%	60.6%	86.2%	20.0%	66.2%
Anadarko	Conventional	34.5%	0.940	1.000	0.986	0.700	22.4%	65.5%	87.9%	20.0%	67.9%
	Coalbed	34.5%	0.940	1.000	0.986	0.700	22.4%	65.5%	87.9%	20.0%	67.9%
Arkoma	Conventional	48.0%	0.940	1.000	0.986	0.700	31.1%	52.0%	83.1%	20.0%	63.1%
California	North	55.2%	0.940	1.000	0.986	0.700	35.8%	44.8%	80.6%	20.0%	60.6%
	South	55.2%	0.940	1.000	0.986	0.700	35.8%	44.8%	80.6%	20.0%	60.6%
	Offshore	55.2%	0.940	1.000	0.986	0.700	35.8%	44.8%	80.6%	20.0%	60.6%
Gulf Onshore	Eastern Gulf	33.7%	0.940	1.000	0.986	0.700	21.9%	66.3%	88.1%	20.0%	68.1%
	Western Gulf	44.5%	0.940	1.000	0.986	0.700	28.8%	55.5%	84.4%	20.0%	64.4%
	Black Warrior	90.0%	0.940	1.000	0.986	0.700	58.4%	10.0%	68.4%	20.0%	48.4%
	Coalbed	33.7%	0.940	1.000	0.986	0.700	21.9%	66.3%	88.1%	20.0%	68.1%
	Tight Sands	33.7%	0.940	1.000	0.986	0.700	21.9%	66.3%	88.1%	20.0%	68.1%
Gulf Offshore	Conventional	90.0%	0.940	1.000	0.986	0.700	58.4%	10.0%	68.4%	20.0%	48.4%
North Central	Conventional	74.4%	0.940	1.000	0.986	0.700	48.3%	25.6%	73.9%	20.0%	53.9%
	Shale	74.4%	0.940	1.000	0.986	0.700	48.3%	25.6%	73.9%	20.0%	53.9%
Northern Great Plains	Coalbed	74.4%	0.940	1.000	0.986	0.700	48.3%	25.6%	73.9%	20.0%	53.9%
	Tight	66.7%	0.940	1.000	0.986	0.700	43.2%	33.3%	76.6%	20.0%	56.6%
	Coalbed	66.7%	0.940	1.000	0.986	0.700	43.2%	33.3%	76.6%	20.0%	56.6%
Pacific Northwest	Conventional	66.7%	0.940	1.000	0.986	0.700	43.2%	33.3%	76.6%	20.0%	56.6%
	Coalbed	56.7%	0.940	1.000	0.986	0.700	36.8%	43.3%	80.1%	20.0%	60.1%
Permian	Conventional	56.7%	0.940	1.000	0.986	0.700	36.8%	43.3%	80.1%	20.0%	60.1%
	Coalbed	57.3%	0.940	1.000	0.986	0.700	37.2%	42.7%	79.9%	20.0%	59.9%
	Tight Sands	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
Rocky Mountains	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Coalbed	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Tight Sands	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
San Juan Basin	Conventional	48.0%	0.940	1.000	0.986	0.700	31.1%	52.0%	83.2%	20.0%	63.2%
	Coalbed	48.0%	0.969	1.000	0.986	0.700	32.1%	52.0%	84.1%	20.0%	64.1%
	Tight Sands	48.0%	0.940	1.000	0.986	0.700	31.1%	52.0%	83.2%	20.0%	63.2%
British Columbia	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Coalbed	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
Alberta	Foothills	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	South Central	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Frontier	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Coalbed	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
Saskatchewan	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
East Canada	Conventional	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
North Canada	Onshore	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%
	Offshore	68.0%	0.940	1.000	0.986	0.700	44.1%	32.0%	76.1%	20.0%	56.1%

Notes: 1) Canadian factors based on corresponding resource types in the Rocky Mountains.
2) Drilling cost reduction factors derived based on review of technology-related literature.
3) Pacific Northwest factors based on average for the Lower 48.

ATTACHMENT C

NATURAL GAS DEMAND PROJECTIONS

Core Demand by NARG Region - TCF per Year									
NARG Region	1999	2004	2009	2014	2019	2024	2029	2034	2039
Lower 48									
East North Central	2.9590	3.0348	3.1067	3.1835	3.2481	3.2717	3.2797	3.2827	3.2839
East South Central	0.6181	0.6693	0.7152	0.7596	0.7993	0.8145	0.8199	0.8221	0.8231
Middle Atlantic	1.6476	1.6691	1.7052	1.7483	1.7789	1.7895	1.7932	1.7948	1.7955
New England	0.4350	0.4640	0.4975	0.5284	0.5552	0.5654	0.5689	0.5702	0.5708
Pacific Northwest	0.2528	0.2713	0.2899	0.3058	0.3200	0.3254	0.3274	0.3281	0.3284
Rocky Mountains	0.4414	0.4677	0.4916	0.5137	0.5333	0.5407	0.5432	0.5441	0.5445
South Atlantic	1.1277	1.2368	1.3562	1.4766	1.5827	1.6229	1.6367	1.6415	1.6434
Southwest Desert	0.1791	0.1938	0.2073	0.2193	0.2300	0.2342	0.2358	0.2366	0.2371
West North Central	1.0015	1.0371	1.0731	1.1069	1.1358	1.1465	1.1502	1.1517	1.1524
West South Central	2.1809	2.3374	2.4652	2.5753	2.6814	2.7224	2.7364	2.7414	2.7436
California									
PG&E	0.2620	0.2730	0.2830	0.2970	0.3110	0.3150	0.3190	0.3220	0.3260
SoCalGas	0.4040	0.4330	0.4590	0.4830	0.5070	0.5130	0.5190	0.5250	0.5280
SDG&E	0.0590	0.0650	0.0700	0.0750	0.0790	0.0800	0.0810	0.0820	0.0840
Non-Utility									
Northern California	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Southern California	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
EOR	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Canada									
British Columbia	0.1390	0.1559	0.1736	0.1919	0.2119	0.2119	0.2119	0.2119	0.2119
Eastern Canada	0.2027	0.2198	0.2356	0.2583	0.2850	0.2850	0.2850	0.2850	0.2850
Ontario	0.7901	0.8490	0.8977	0.9486	1.0038	1.0038	1.0038	1.0038	1.0038
Western Canada	0.8131	0.8966	0.9415	1.0210	1.1219	1.1219	1.1219	1.1219	1.1219
Mexico									
Baja	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
North	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
East	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total									
Lower 48 (No CA)	10.8431	11.3814	11.9078	12.4174	12.8647	13.0331	13.0914	13.1131	13.1226
California	0.7250	0.7710	0.8120	0.8550	0.8970	0.9080	0.9190	0.9290	0.9380
Canada	1.9449	2.1212	2.2484	2.4198	2.6225	2.6225	2.6225	2.6225	2.6225
Mexico	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Source: Lower 48 (Except California) - GRI Baseline Projection Databook (1996)
California - 1996 Electricity Report
Canada - Canadian Gas Association
Mexico - Energy Information Administration

Notes: 1) Data after 2010 are extrapolations.
2) Noncore demand includes oil consumption on a gas equivalent basis of noncore facilities with fuel switching capability.
3) California non-utility demand is only natural gas.

Noncore Demand by NARG Region - TCF per Year									
NARG Region	1999	2004	2009	2014	2019	2024	2029	2034	2039
Lower 48									
East North Central	0.9321	1.0866	1.2064	1.4615	1.6216	1.7733	1.8010	1.8959	1.9005
East South Central	0.4022	0.4705	0.5094	0.6260	0.6887	0.7559	0.7675	0.8150	0.8174
Middle Atlantic	1.1846	1.4087	1.7019	1.8934	2.0995	2.2603	2.3100	2.3705	2.3793
New England	0.5196	0.6002	0.6756	0.7157	0.7562	0.8008	0.8170	0.8349	0.8386
Pacific Northwest	0.1740	0.2136	0.2441	0.2823	0.3040	0.3321	0.3361	0.3561	0.3568
Rocky Mountains	0.1637	0.2006	0.2458	0.3229	0.3700	0.4254	0.4355	0.4728	0.4746
South Atlantic	1.1266	1.3124	1.5402	1.7233	1.8863	2.0217	2.0615	2.1204	2.1280
Southwest Desert	0.1457	0.1826	0.1966	0.1958	0.1979	0.2094	0.2109	0.2202	0.2206
West North Central	0.3611	0.4638	0.6143	0.8936	1.1497	1.3424	1.3936	1.4774	1.4847
West South Central	3.5097	3.9200	4.0268	4.2133	4.2720	4.4936	4.5093	4.7042	4.7074
California									
PG&E	0.4740	0.5140	0.5850	0.6250	0.6650	0.6750	0.6850	0.6950	0.7050
SoCalGas	0.4210	0.5040	0.5450	0.6010	0.6300	0.6440	0.6520	0.6610	0.6690
SDG&E	0.0600	0.0920	0.1030	0.1220	0.1310	0.1360	0.1410	0.1460	0.1510
Non-Utility									
Northern California	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200
Southern California	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180
EOR	0.2880	0.2870	0.2840	0.2780	0.2760	0.2750	0.2750	0.2750	0.2740
Canada									
British Columbia	0.0771	0.0943	0.0975	0.1000	0.1033	0.1033	0.1033	0.1033	0.1033
Eastern Canada	0.1123	0.1215	0.1343	0.1561	0.1959	0.1959	0.1959	0.1959	0.1959
Ontario	0.2643	0.2817	0.2990	0.3295	0.3707	0.3707	0.3707	0.3707	0.3707
Western Canada	0.2563	0.3179	0.3621	0.4467	0.5732	0.5732	0.5732	0.5732	0.5732
Mexico									
Baja	0.0050	0.1370	0.1430	0.1500	0.1570	0.1570	0.1570	0.1570	0.1570
North	0.0820	0.0870	0.0910	0.0960	0.0810	0.0810	0.0810	0.0810	0.0810
East	0.0620	0.1390	0.1460	0.1540	0.1290	0.1290	0.1290	0.1290	0.1290
Total									
Lower 48 (No CA)	8.5193	9.8589	10.9611	12.3278	13.3458	14.4150	14.6424	15.2675	15.3080
California	1.2810	1.4350	1.5550	1.6640	1.7400	1.7680	1.7910	1.8150	1.8370
Canada	0.7100	0.8154	0.8928	1.0323	1.2432	1.2432	1.2432	1.2432	1.2432
Mexico	0.1500	0.3630	0.3810	0.3990	0.3670	0.3670	0.3670	0.3670	0.3670

Source: Lower 48 (Except California) - GRI Baseline Projection Databook (1996)
California - 1996 Electricity Report
Canada - Canadian Gas Association
Mexico - Energy Information Administration

Notes: 1) Data after 2010 are extrapolations.
2) Noncore demand includes oil consumption on a gas equivalent basis of noncore facilities with fuel switching capability.
3) California non-utility demand is only natural gas.

Total Demand by NARG Region - TCF per Year									
NARG Region	1999	2004	2009	2014	2019	2024	2029	2034	2039
Lower 48									
East North Central	3.8911	4.1211	4.3131	4.6449	4.8698	5.0450	5.0808	5.1786	5.1844
East South Central	1.0203	1.1398	1.2246	1.3856	1.4879	1.5704	1.5875	1.6370	1.6405
Middle Atlantic	2.8322	3.0778	3.4071	3.6417	3.8784	4.0498	4.1032	4.1652	4.1748
New England	0.9546	1.0642	1.1731	1.2441	1.3114	1.3662	1.3859	1.4051	1.4094
Pacific Northwest	0.4268	0.4849	0.5340	0.5881	0.6239	0.6575	0.6635	0.6842	0.6853
Rocky Mountains	0.6052	0.6685	0.7376	0.8368	0.9035	0.9664	0.9790	1.0172	1.0195
South Atlantic	2.2543	2.5492	2.8964	3.1999	3.4690	3.6447	3.6982	3.7619	3.7714
Southwest Desert	0.3248	0.3763	0.4038	0.4151	0.4279	0.4436	0.4468	0.4569	0.4577
West North Central	1.3626	1.5009	1.6874	2.0006	2.2854	2.4888	2.5438	2.6290	2.6371
West South Central	5.6906	6.2573	6.4920	6.7887	6.9534	7.2160	7.2457	7.4457	7.4510
California									
PG&E	0.7360	0.7870	0.8680	0.9220	0.9760	0.9900	1.0040	1.0170	1.0310
SoCalGas	0.8250	0.9370	1.0040	1.0840	1.1370	1.1570	1.1710	1.1860	1.1970
SDG&E	0.1190	0.1570	0.1730	0.1970	0.2100	0.2160	0.2220	0.2280	0.2350
Non-Utility									
Northern California	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200	0.0200
Southern California	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180	0.0180
EOR	0.2880	0.2870	0.2840	0.2780	0.2760	0.2750	0.2750	0.2750	0.2740
Canada									
British Columbia	0.2161	0.2502	0.2711	0.2919	0.3152	0.3152	0.3152	0.3152	0.3152
Eastern Canada	0.3150	0.3413	0.3699	0.4144	0.4809	0.4809	0.4809	0.4809	0.4809
Ontario	1.0544	1.1307	1.1967	1.2781	1.3745	1.3745	1.3747	1.3747	1.3747
Western Canada	1.0694	1.2145	1.3036	1.4677	1.6951	1.6951	1.6951	1.6951	1.6951
Mexico									
Baja	0.0050	0.1370	0.1430	0.1500	0.1570	0.1570	0.1570	0.1570	0.1570
North	0.0820	0.0870	0.0910	0.0960	0.0810	0.0810	0.0810	0.0810	0.0810
East	0.0620	0.1390	0.1460	0.1540	0.1290	0.1290	0.1290	0.1290	0.1290
Total									
Lower 48 (No CA)	19.3625	21.2405	22.8691	24.7455	26.2107	27.4484	27.7342	28.3809	28.4310
California	2.0060	2.2060	2.3670	2.5190	2.6370	2.6760	2.7100	2.7440	2.7750
Canada	2.6549	2.9366	3.1412	3.4521	3.8657	3.8657	3.8657	3.8657	3.8657
Mexico	0.1500	0.3630	0.3810	0.3990	0.3670	0.3670	0.3670	0.3670	0.3670

Source: Lower 48 (Except California) - GRI Baseline Projection Databook (1996)
California - 1996 Electricity Report
Canada - Canadian Gas Association
Mexico - Energy Information Administration

Notes: 1) Data after 2010 are extrapolations.
2) Noncore demand includes oil consumption on a gas equivalent basis of noncore facilities with fuel switching capability.
3) California non-utility demand is only natural gas.

ATTACHMENT D
FR97 TRANSPORTATION COSTS, CAPACITIES, AND LINE LOSSES FOR NARG MODEL CORRIDORS

NARG Sector	NARG Activity	Interstate Pipeline Corridors	FR95	FR97	Maximum Pipeline Capacity		Line Losses	Source of FR97 Transport Cost
			'93\$/mcf	'95\$/mcf	TCF	BCF/D		
1	5	ANGTS to Alberta	4.550	4.550	0.700	1.918	0.80%	1995 Fuels Report
1	6	TAGS to S Alaska	1.800	1.800	N/A	N/A	3.00%	1995 Fuels Report
2	9	S Alaska to Asia	1.700	1.700	0.420	1.151	0.00%	1995 Fuels Report
3	11	San Juan to Topock (EP-N)	0.167	0.186	1.240	3.397	2.50%	50% of EPNG/TW SJ-CA Rate (Effective 1/96)
3	6	San Juan to Rocky Mtns	0.254	0.276	0.122	0.334	1.50%	Northwest Pipeline
3	18	San Juan to Anadarko	--	0.279	0.035	0.096	1.60%	CIG Rate (Off-System)
3	9	San Juan to Permian	0.187	0.190	0.448	1.227	5.00%	EPNG/TW Combined (Effective 10/94)
3	5	Topock to EOR (Via Mojave)	0.485	0.507	0.146	0.400	2.50%	50% EPNG: SJ to CA Border + Mojave (Effective 1/1/96)
3	3	Topock to Southern CA Supply (Via EP-N)	0.167	0.186	0.526	1.441	2.50%	50% EPNG/TW SJ-CA Rate (Effective 1/96)
3	4	Topock to Northern CA Supply (Via EP-N)	0.167	0.186	0.416	1.140	2.50%	50% EPNG/TW SJ-CA Rate (Effective 1/96)
3	7	Topock to SW Desert - AZ/NM (Via EP-N)	--	0.070	0.292	0.800	2.50%	EPNG SJ to AZ/NM Tariff - NARG Rate (SJ-Topock)
3	13	Topock to Blythe (Via Havasu Crossover)	0.000	0.000	N/A	N/A	0.00%	Rate Incorporated in Other Corridors
3	15	Topock to SW Desert - NV (Via EP-N)	--	0.128	0.082	0.225	2.50%	EPNG SJ to NV Tariff - NARG Rate (SJ-Topock)
4	18	Rocky Mtns to EOR (Through 1992-2007)	0.674	0.674	0.256	0.701	1.00%	100% Kern River (Years 1-15)
4	18	Rocky Mtns to EOR (Beyond 2007)	0.402	0.402	0.256	0.701	1.00%	100% Kern River (Years 16-25)
4	14	Rocky Mtns to San Juan Basin	0.245	0.276	0.233	0.638	1.50%	Northwest Pipeline
4	15	Rocky Mtns to WNC Demand	0.270	0.236	0.236	0.647	0.50%	Trailblazer, KN Interstate
4	16	Rocky Mtns to Rocky Mtn Demand	--	0.185	0.571	1.564	1.50%	Questar Pipeline, CIG (On-System Rate)
4	17	Rocky Mtn to Anadarko	0.207	0.228	0.237	0.649	1.60%	CIG, Williams Natural Gas, KN Interstate
4	25	Rocky Mtn to Pacific Northwest	--	0.276	0.162	0.444	1.60%	Northwest Pipeline
5	13	NGPlains to Rocky Mtn Demand (Montana)	--	0.350	0.127	0.348	3.40%	Williston Basin
5	14	NGPlains to WNC Demand	0.564	0.350	0.075	0.205	3.40%	Williston Basin
5	16	NGPlains to Rocky Mtn Demand (WY/CO)	--	0.174	0.100	0.274	1.40%	CIG (On-System Rate)
6	4	Anadarko to WNC Demand	0.207	0.186	2.207	6.047	2.90%	Northern Natural, Panhandle Eastern, Williams, KN Interstate
6	6	Anadarko to Permian Basin	0.169	0.104	0.735	2.014	1.40%	EPNG (Anadarko-Production Area)
6	7	Anadarko to WSC Demand	0.176	0.192	3.016	8.263	1.20%	Spot Price Differential (1/95-12/95)
6	8	Anadarko to ESC Demand	0.148	0.247	0.188	0.515	2.50%	Noram Gas Transmission
7	11	Permian to El Paso -South Allocation (Blythe)	0.164	0.186	0.457	1.252	2.50%	50% of EPNG: Permian to CA (Effective 1/1/96)
7	7	Permian to Anadarko	0.086	0.104	0.653	1.789	1.40%	EPNG (Permian-Production Area)
7	9	Permian to WSC Demand	0.091	0.091	0.475	1.301	1.20%	Valero
7	10	Permian to San Juan (EP-N)	0.000	0.000	0.522	1.430	2.50%	Rate Incorporated in Other Corridors
7	13	Permian to Gulf	0.234	0.234	0.602	1.649	1.00%	Valero
7	8	Blythe (EP-S Allocation) to SW Desert - AZ/NM	--	0.075	0.188	0.515	2.50%	EPNG Permian to AZ/NM Tariff - NARG Rate (Permian-Blythe)
7	12	Blythe (EP-S Allocation) to Mexico	--	0.075	0.168	0.460	2.50%	EPNG Permian to AZ/NM Tariff - NARG Rate (Permian-Blythe)
7	21	Blythe to Southern CA Supply (Via EP-S)	0.164	0.186	0.515	1.411	2.50%	50% of EPNG: Permian to CA (Effective 1/1/96)
8	8	Gulf Coast to WSC Demand	0.151	0.127	7.290	19.973	1.10%	Tennessee Gas, Transcontinental, Texas Eastern
8	9	Gulf Coast to Permian Basin	0.234	0.234	0.420	1.151	1.00%	Valero
8	10	Gulf Coast to ESC Demand	0.158	0.172	7.584	20.778	1.20%	Tennessee Gas, Transcontinental, Texas Eastern, Southern Natural
8	15	Gulf Coast to Mexico Demand (East)	--	0.040	0.494	1.353	0.50%	1995 Fuels Report Sensitivity
9	8	N Central to ENC Demand	0.308	0.307	0.408	1.118	3.00%	East Ohio Off-System Rate
9	9	N Central to ESC Demand	0.308	0.307	0.070	0.192	5.00%	East Ohio Off-System Rate
10	11	Appalachia to S Atlantic Demand	0.434	0.239	0.622	1.704	2.30%	Columbia Gas
10	12	Appalachia to Mid-Atlantic Demand	0.491	0.171	0.664	1.819	2.40%	National Fuel, Columbia Gas, CNG, Equitrans
12	3	Mexico to Gulf Coast	1.050	1.050	0.700	1.918	0.00%	1995 Fuels Report
13	10	Sumas to Pacific NW	0.254	0.276	0.343	0.940	1.60%	Northwest Pipeline
13	11	S Alberta to Rocky Mtn Demand (Montana)	0.183	0.182	0.040	0.110	2.00%	Montana Power
13	7	S Alberta to Stanfield	0.210	0.116	0.909	2.490	1.10%	45.3% of PGT Rolled-in Tariff
13	15	Stanfield to Pacific NW (Reno Lateral)	0.324	0.235	0.198	0.542	2.60%	Northwest Pipeline
13	21	Stanfield to Malin	0.254	0.140	0.657	1.800	1.40%	54.7% of PGT Rolled-in Tariff
13	22	Stanfield to PNW Demand (Via NWPL)	0.254	0.276	0.054	0.148	1.50%	Northwest Pipeline
13	9	Malin to PG&E (PG&E Line 400)	0.155	0.215	0.381	1.044	0.00%	PG&E Noncore Backbone Rate (Reported in Gas Accord Filing)
13	8	Malin to Southern CA Supply (PG&E Line 401)	0.337	0.337	0.219	0.600	3.50%	PG&E Tariffs (Effective 5/94)
13	19	Malin to Northern CA Supply (PG&E Line 401)	0.215	0.215	0.276	0.756	3.50%	PG&E Tariffs (Effective 5/94)
13	24	Malin to PNW Demand (Reno)	--	0.470	0.041	0.112	2.00%	Tuscarora Pipeline
13	12	East Montana to WNC (Northern Border)	0.444	0.337	0.545	1.493	1.70%	Northern Border (Monchy-Ventura)
13	16	WNC to ENC (Northern Border)	0.079	0.060	0.138	0.378	0.20%	Northern Border (Ventura-Harper)
13	13	West Minn to ENC	0.362	0.219	0.278	0.762	6.50%	Viking Gas, Great Lakes
13	14	New York to Mid Atlantic	0.034	0.334	0.756	2.071	1.60%	Tennessee Gas, Iroquois
13	20	Vermont to New England	--	0.093	0.023	0.063	0.50%	Granite State
14	3	LNG to Gulf	2.250	2.250	0.365	1.000	0.00%	1995 Fuels Report
14	4	LNG to So Atlantic	1.880	1.880	0.219	0.600	0.00%	1995 Fuels Report
14	5	LNG to Mid Atlantic	1.950	1.950	0.548	1.501	0.00%	1995 Fuels Report
14	9	LNG to New England	1.770	1.770	0.164	0.449	0.00%	1995 Fuels Report
15	7	Pacific NW to CA Border	0.254	0.140	0.073	0.200	1.40%	54.7% PGT Rolled-in Tariff
15	8	Pacific NW to Rocky Mtn Supply	0.254	0.000	0.109	0.299	0.00%	Incorporated in Other Corridors
15	9	Pacific NW to PNW Demand (Reno)	--	0.259	0.059	0.162	2.50%	Paiute Pipeline
15	10	Pacific NW to Rocky Mtn Demand (Idaho)	--	0.000	N/A	0.000	1.50%	Incorporated in Other Corridors
16	14	WNC to ENC (Except Northern Border)	0.594	0.143	1.769	4.847	2.90%	Northern Natural, Panhandle Eastern
18	9	ENC to Mid-Atlantic	0.397	0.295	1.601	4.386	1.90%	Texas Eastern, Tennessee Gas, CNG
18	10	ENC to Ontario	0.192	0.142	0.071	0.195	1.00%	Panhandle Eastern
19	13	ESC to ENC	0.169	0.296	4.223	11.570	3.00%	Texas Eastern, Tennessee Gas
19	14	ESC to So Atlantic	0.117	0.142	3.391	9.290	1.70%	Transcontinental, Southern Natural

ATTACHMENT D
FR97 TRANSPORTATION COSTS, CAPACITIES, AND LINE LOSSES FOR NARG MODEL CORRIDORS

NARG Sector	NARG Activity	Interstate Pipeline Corridors	FR95	FR97	Maximum Pipeline Capacity		Line Losses	Source of FR97 Transport Cost
			'93\$/mcf	'95\$/mcf	TCF	BCF/D		
20	13	So Atlantic to Mid-Atlantic	0.207	0.171	1.021	2.797	2.30%	Transco, Columbia, CNG
21	13	Mid-Atlantic to New England	0.350	0.243	0.764	2.093	1.20%	Tennessee Gas, Algonquin, Iroquois
23	2	Southern CA Supply to SoCalGas	0.000	0.000	1.000	2.740	0.50%	1995 Fuels Report
23	3	Southern CA Supply to SDG&E	0.354	0.292	0.146	0.400	0.50%	SoCalGas Tariff Sheet 27591-G, Effective 1/1/96.
23	4	Southern CA Supply to EOR	0.098	0.098	0.146	0.400	0.50%	Avg California Transport Rate
23	13	Southern CA Supply (Wheeler Ridge)	0.000	0.000	0.197	0.540	0.00%	SoCalGas Tariff Sheet 27685-G, Effective 3/1/96.
23	14	Southern CA Supply Direct Link	0.098	0.098	0.256	0.701	0.50%	Avg California Transport Rate
23	16	Southern CA Supply to Mexico (Baja)	--	0.200	0.197	0.540	2.00%	1995 Fuels Report Sensitivity
24	2	Northern CA Supply to PG&E	0.000	0.215	0.964	2.641	0.50%	PG&E Noncore Backbone Rate (Reported in Gas Accord Filing)
24	10	Northern CA Supply Direct Link	0.098	0.098	0.110	0.301	2.00%	Avg California Transport Rate
25	13	SoCalGas to EOR	0.421	0.341	0.160	0.438	0.50%	SoCalGas Tariff Sheet 27586-G, Effective 1/1/96.
26	13	PG&E to EOR	0.234	0.224	0.160	0.438	0.50%	CPUC Decision 95-12-053, 12/95.
28	5	EOR to Southern CA Supply	0.000	0.000	0.146	0.400	0.00%	1995 Fuels Report
28	4	EOR to Northern CA Supply (Via KR/Mojave)	0.000	0.000	0.073	0.200	0.00%	PG&E Kern River Station Charge
1,2	9	BC to BC Demand	0.150	0.158	0.219	0.600	1.60%	Westcoast Inland Toll
1,2	5	BC to Washington	0.071	0.070	0.365	1.000	1.40%	Westcoast Export Toll
1,2	6	BC to Alberta	0.218	0.232	0.068	0.186	1.00%	Westcoast to Alberta Toll
2,2	5	Alberta to Western Canada	0.085	0.105	1.071	2.934	1.20%	NOVA Provincial
2,2	6	Alberta to East Montana	0.228	0.267	0.562	1.540	1.20%	NOVA export + Foothills to N.Border
2,2	7	Alberta to Saskatchewan	0.276	0.299	2.332	6.389	1.20%	NOVA export + TCPL to Saskatchewan
2,2	8	Alberta to S Alberta	0.223	0.258	1.190	3.260	1.20%	NOVA export + ANG to PGT
3,2	4	Saskatchewan to Western Canada	0.219	0.245	0.200	0.548	1.30%	TCPL to Saskatchewan + NOVA Provincial
3,2	5	Saskatchewan to Ontario	0.422	0.440	1.800	4.932	1.30%	TCPL to N Ontario - Saskatchewan
3,2	6	Saskatchewan to West Minn	0.117	0.122	0.433	1.186	1.30%	TCPL to Emerson - Saskatchewan
4,2	4	N Canada Supply to Alberta	1.540	1.540	0.438	1.200	4.00%	1995 Fuels Report
5,2	4	E Canada Supply to E Canada Demand	1.600	1.600	N/A	0.000	8.00%	1995 Fuels Report
7,2	7	E Canada Demand to Vermont	--	0.000	N/A	0.000	N/A	Incorporated in Other Corridors
9,2	7	Ontario Demand to East Canada Demand	0.111	0.119	0.438	1.200	3.00%	TCPL to East of Ontario - N Ontario
9,2	8	Ontario to New York	0.150	0.157	N/A	0.000	1.40%	TCPL to Niagara - N Ontario

ATTACHMENT E

Charts and Graphs Comparing Base Case and Sensitivity Cases

Note: The EIA 4.4% Case is the Base Case

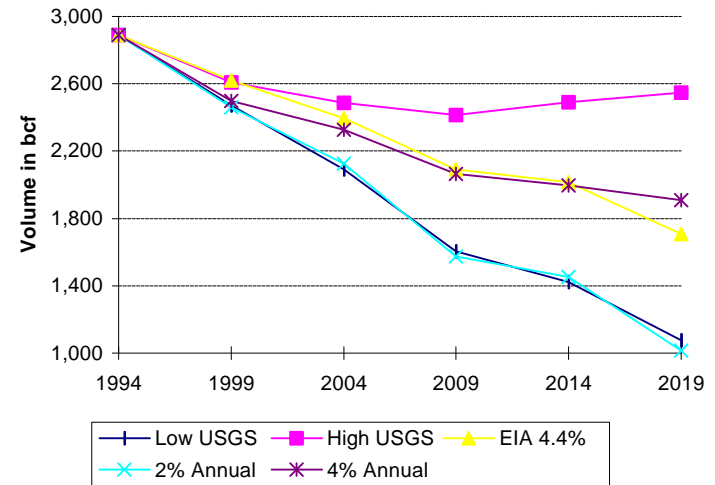
Anadarko

Anadarko Basin Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	2,890	2,470	2,092	1,606	1,422	1,076
High USGS	2,890	2,608	2,487	2,413	2,491	2,549
EIA 4.4%	2,890	2,620	2,396	2,091	2,014	1,709
2% Annual	2,890	2,459	2,126	1,575	1,453	1,014
4% Annual	2,890	2,499	2,326	2,064	1,995	1,909

Anadarko Basin Production

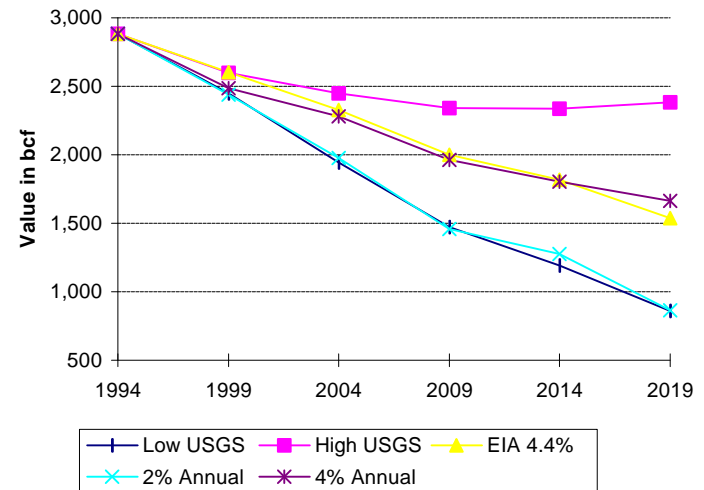


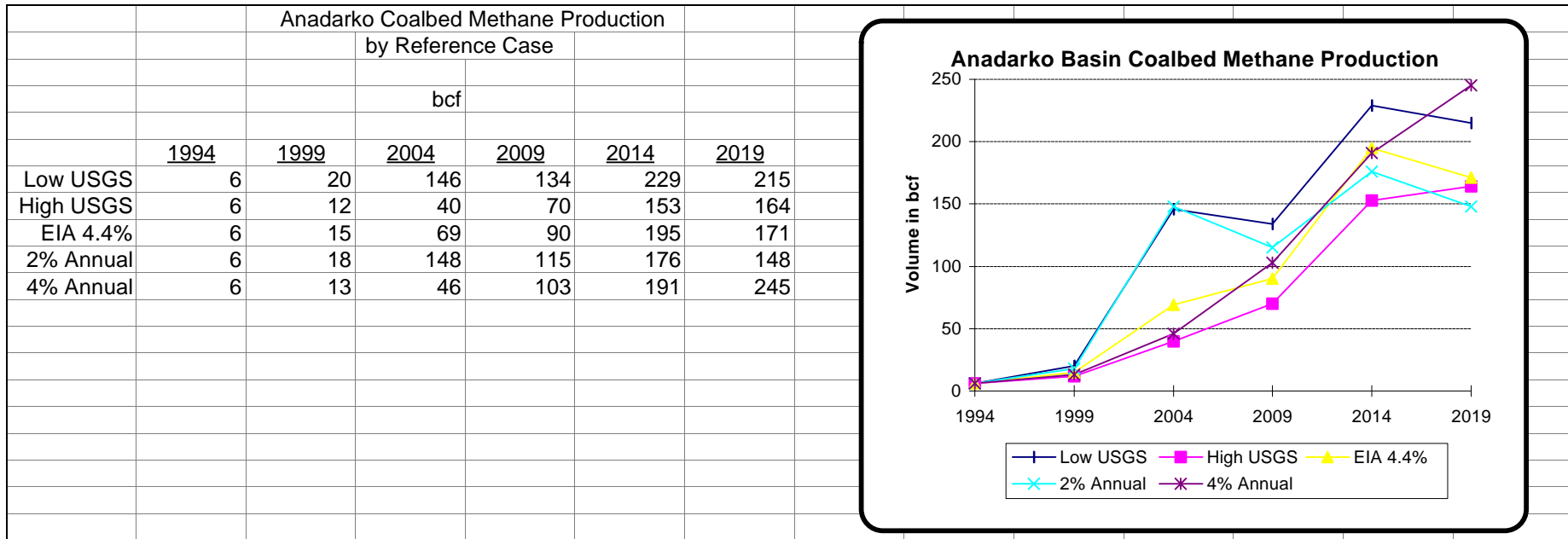
Anadarko Conventional Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	2,884	2,450	1,946	1,472	1,193	861
High USGS	2,884	2,597	2,447	2,343	2,338	2,385
EIA 4.4%	2,884	2,605	2,327	2,001	1,819	1,538
2% Annual	2,884	2,441	1,978	1,460	1,277	866
4% Annual	2,884	2,486	2,279	1,961	1,803	1,664

Anadarko Basin Conventional Production

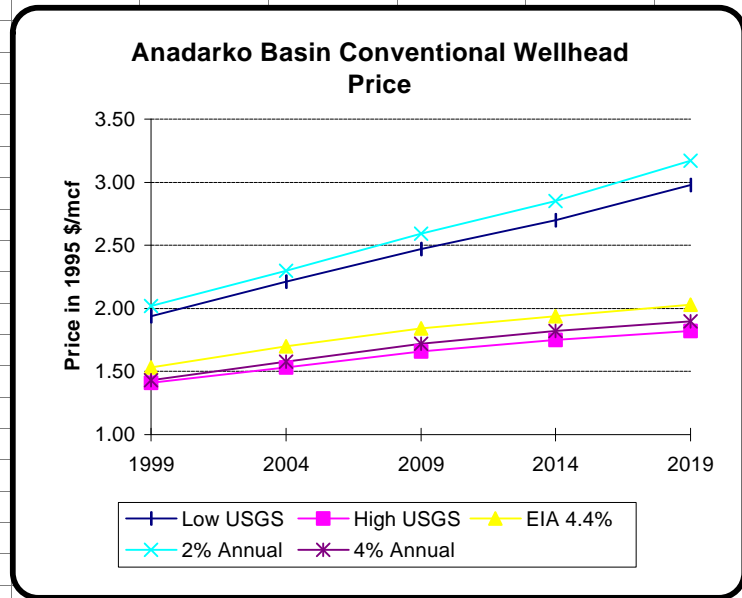
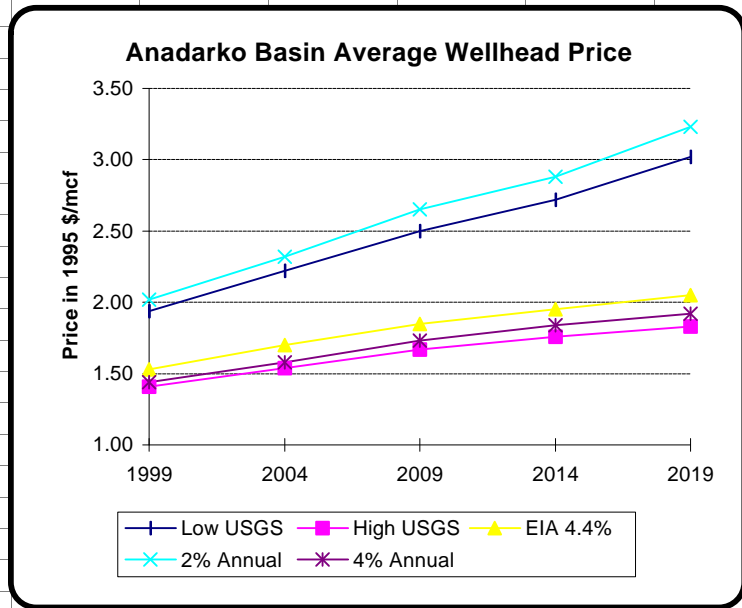




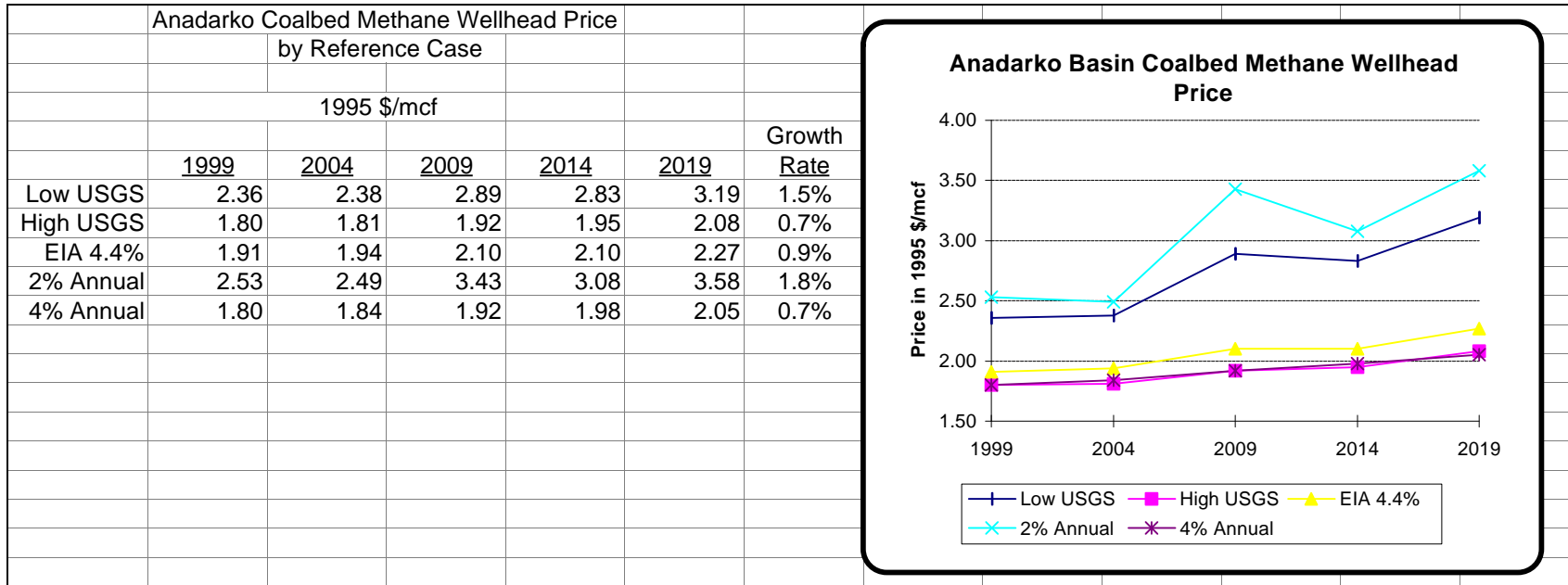
Anadarko

Anadarko Average Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.94	2.22	2.50	2.72	3.02	2.2%
High USGS	1.41	1.54	1.67	1.76	1.83	1.3%
EIA 4.4%	1.53	1.70	1.85	1.95	2.05	1.5%
2% Annual	2.02	2.32	2.65	2.88	3.23	2.4%
4% Annual	1.44	1.58	1.73	1.84	1.92	1.4%

Anadarko Conventional Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.94	2.21	2.47	2.70	2.98	2.2%
High USGS	1.41	1.53	1.66	1.75	1.82	1.3%
EIA 4.4%	1.53	1.70	1.84	1.94	2.03	1.4%
2% Annual	2.02	2.30	2.59	2.85	3.17	2.3%
4% Annual	1.43	1.58	1.72	1.82	1.90	1.4%



Anadarko

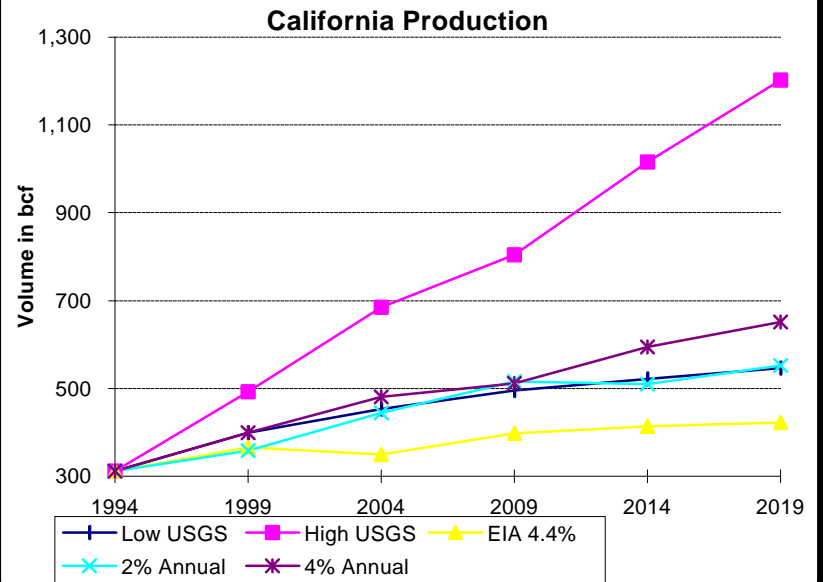


Calif Supply

California Production by Reference Case

bcf

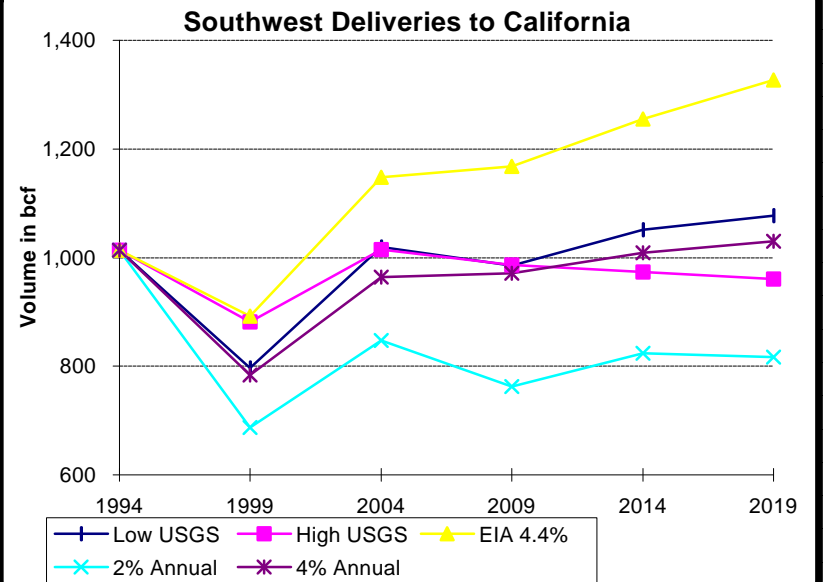
	1994	1999	2004	2009	2014	2019
Low USGS	311	399	453	495	521	546
High USGS	311	493	685	805	1,016	1,202
EIA 4.4%	311	366	350	397	414	422
2% Annual	311	359	444	516	510	552
4% Annual	311	399	481	512	594	651



Southwest Supply by Reference Case

bcf

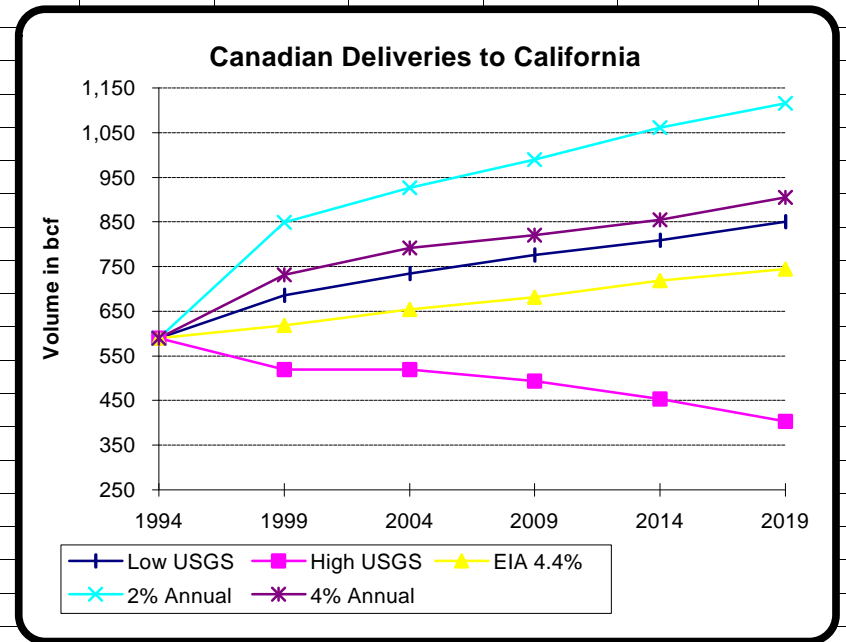
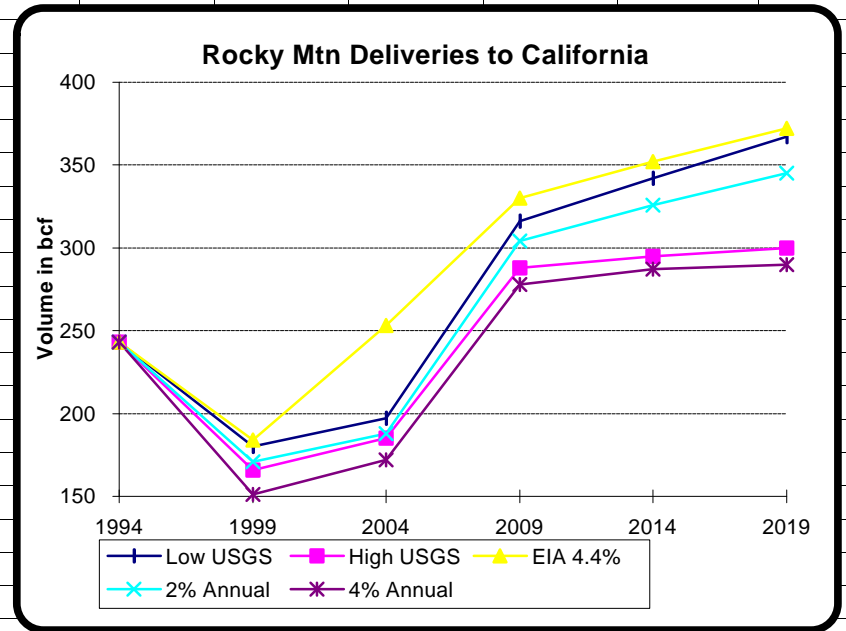
	1994	1999	2004	2009	2014	2019
Low USGS	1,013	797	1,019	985	1,051	1,077
High USGS	1,013	882	1,015	987	973	960
EIA 4.4%	1,013	892	1,148	1,168	1,255	1,327
2% Annual	1,013	687	847	763	824	817
4% Annual	1,013	784	964	971	1,009	1,030



Calif Supply

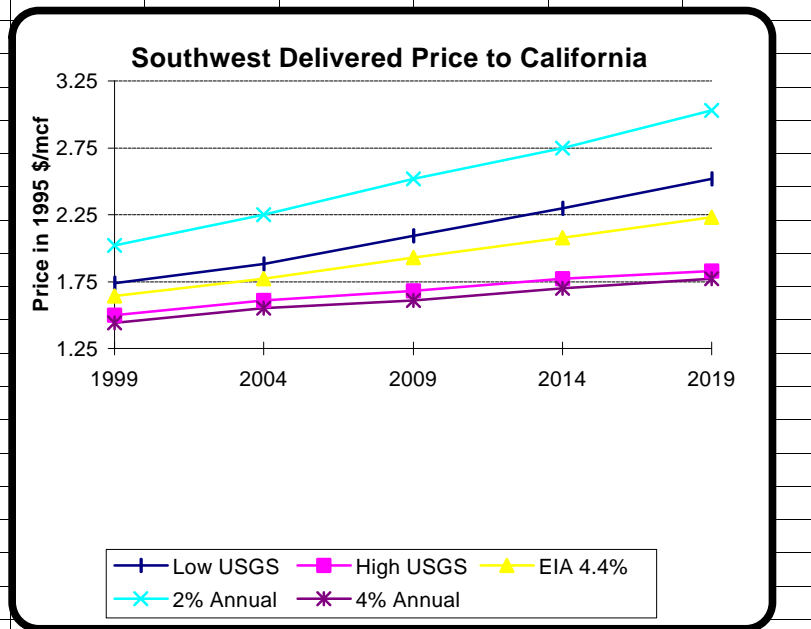
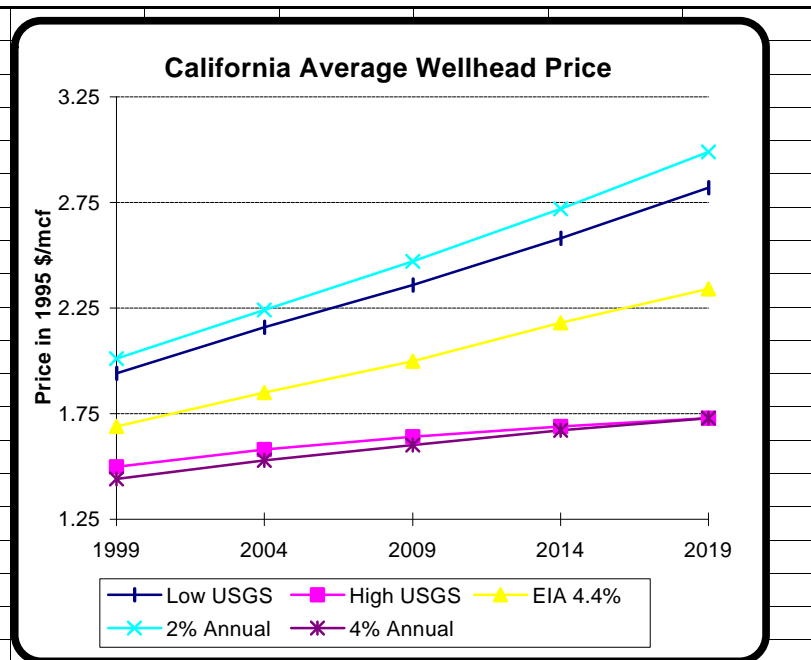
Rocky Mtn Supply by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	243	180	197	316	342	367
High USGS	243	166	185	288	295	300
EIA 4.4%	243	184	253	330	352	372
2% Annual	243	171	188	304	326	345
4% Annual	243	151	172	278	287	290

Canadian Supply by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	590	686	734	776	809	850
High USGS	590	520	519	494	453	403
EIA 4.4%	590	619	654	681	718	744
2% Annual	590	849	927	990	1,061	1,116
4% Annual	590	731	792	820	855	905

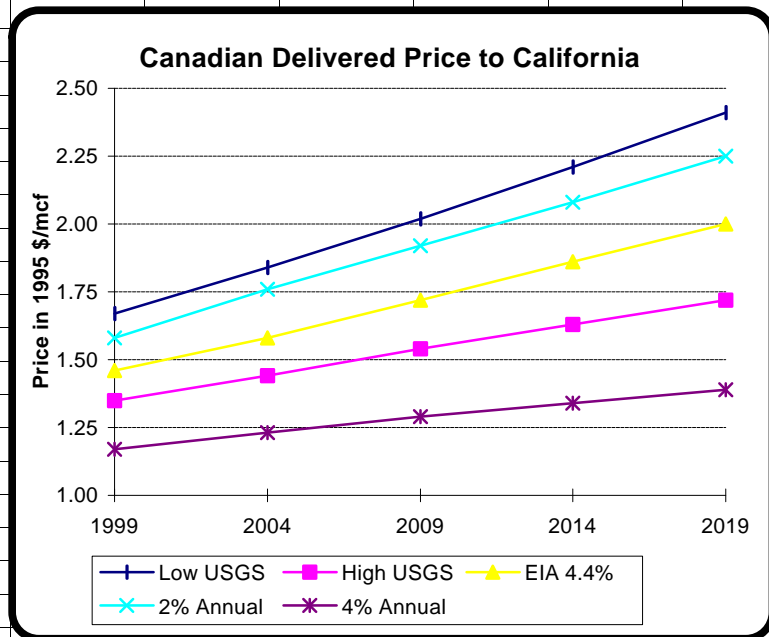
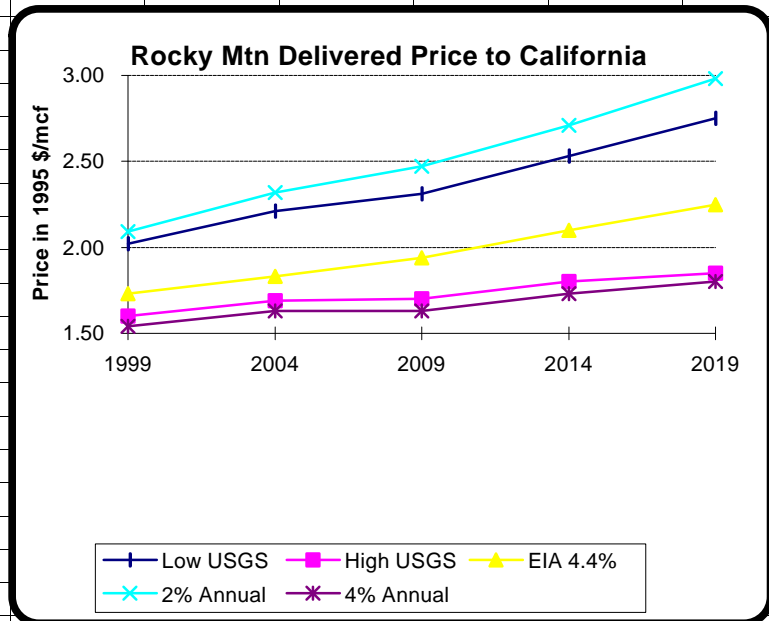


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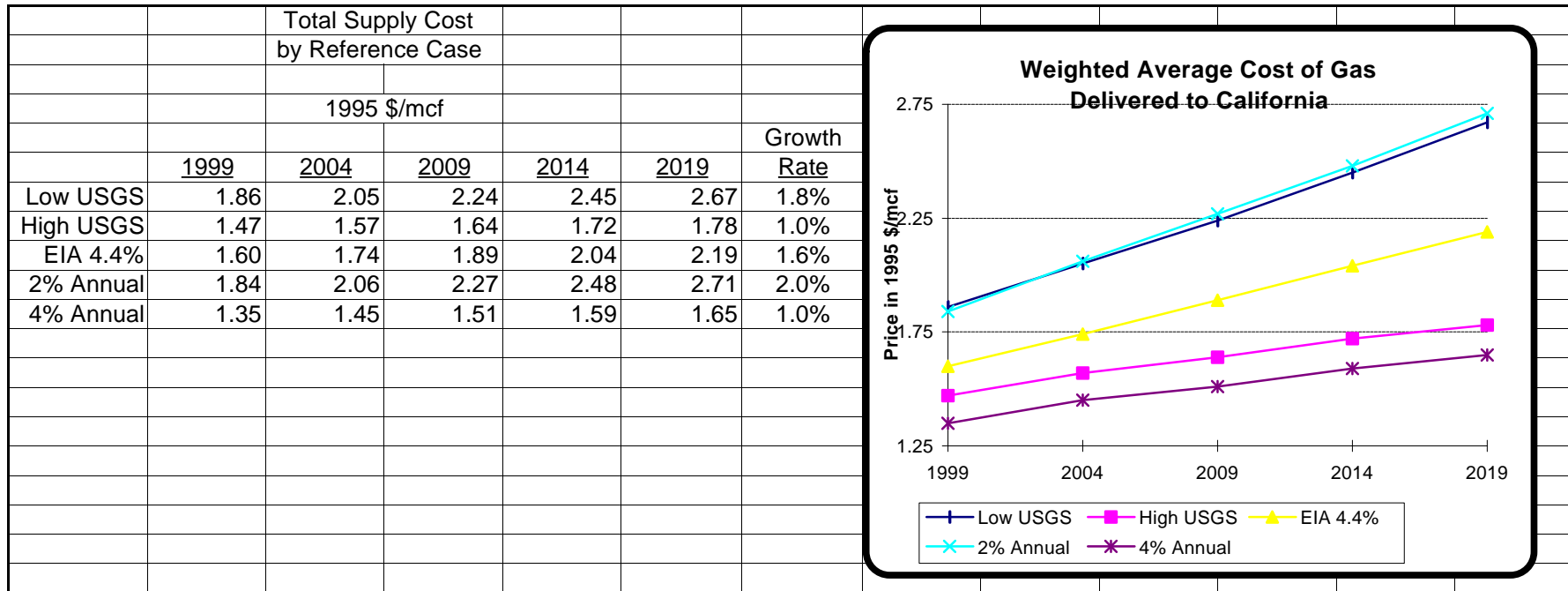
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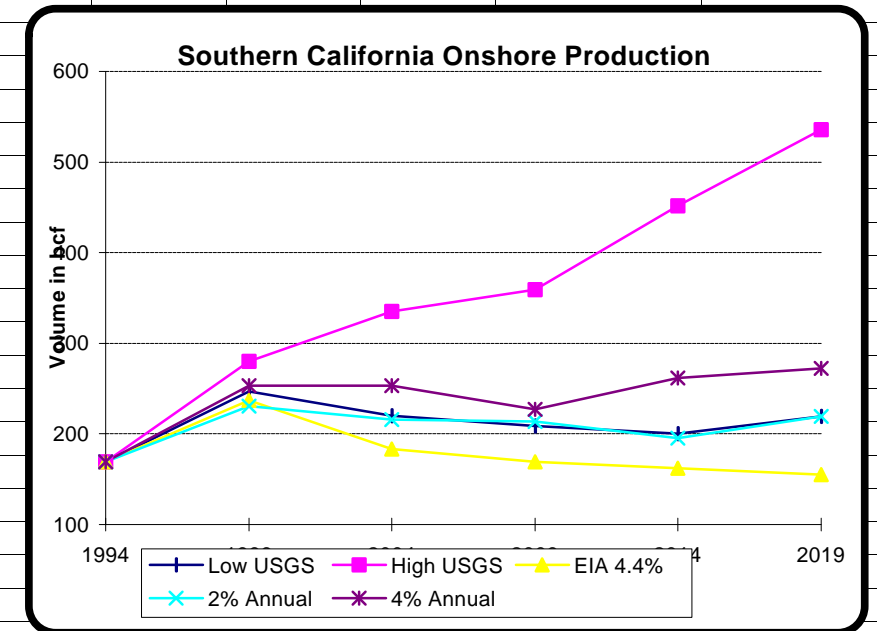
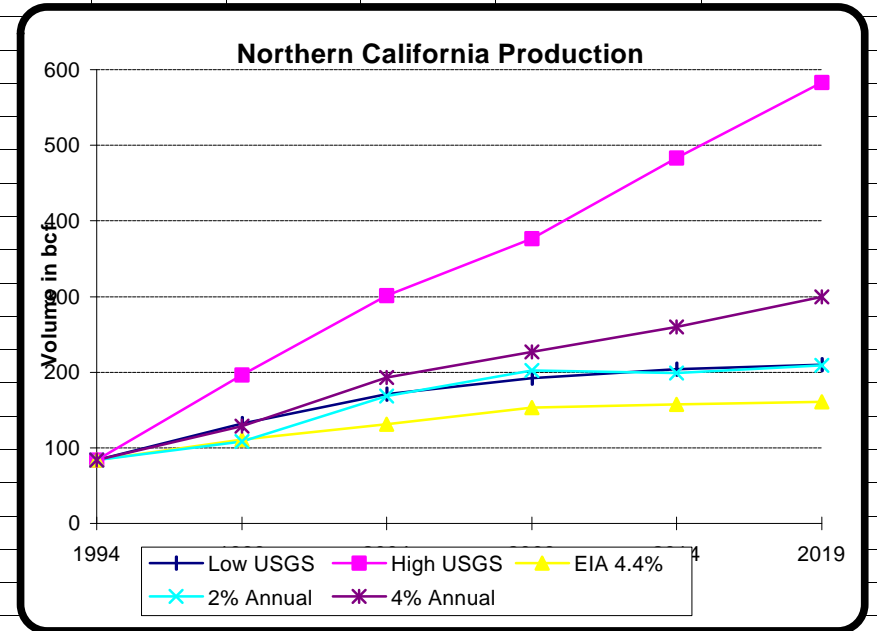
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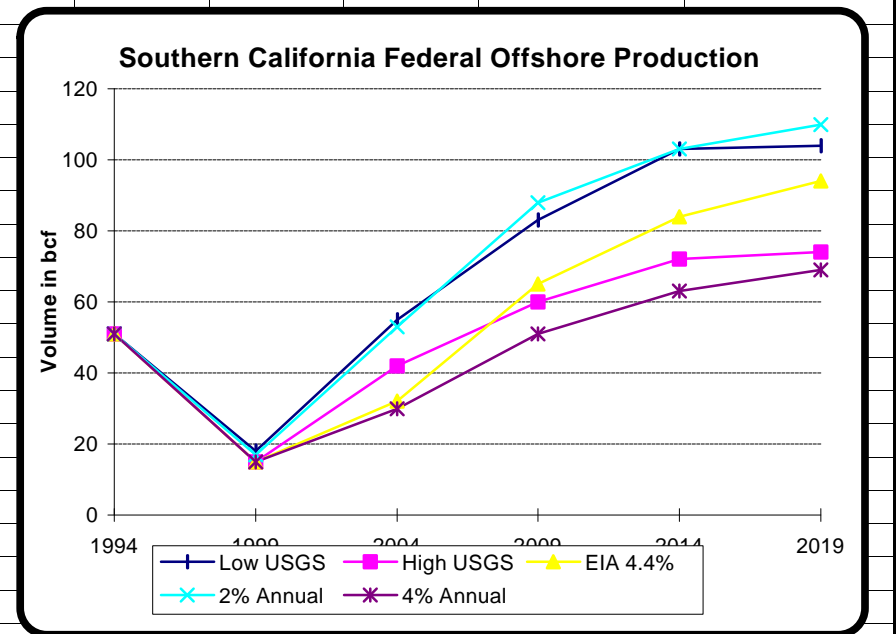
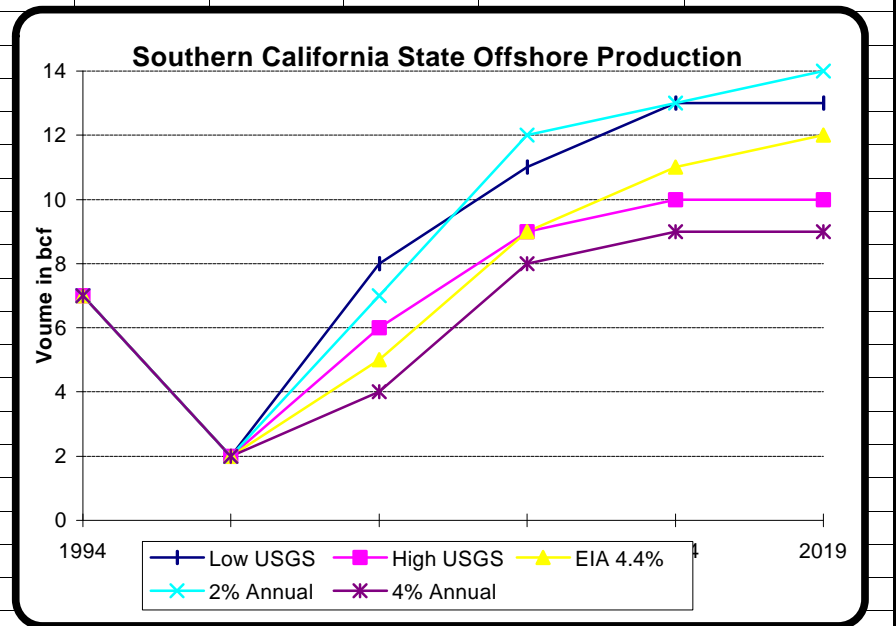
Northern Calif Onshore Production by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	84	132	171	192	204	210
High USGS	84	196	301	377	483	583
EIA 4.4%	84	111	131	153	157	161
2% Annual	84	108	168	202	199	209
4% Annual	84	129	193	227	260	300

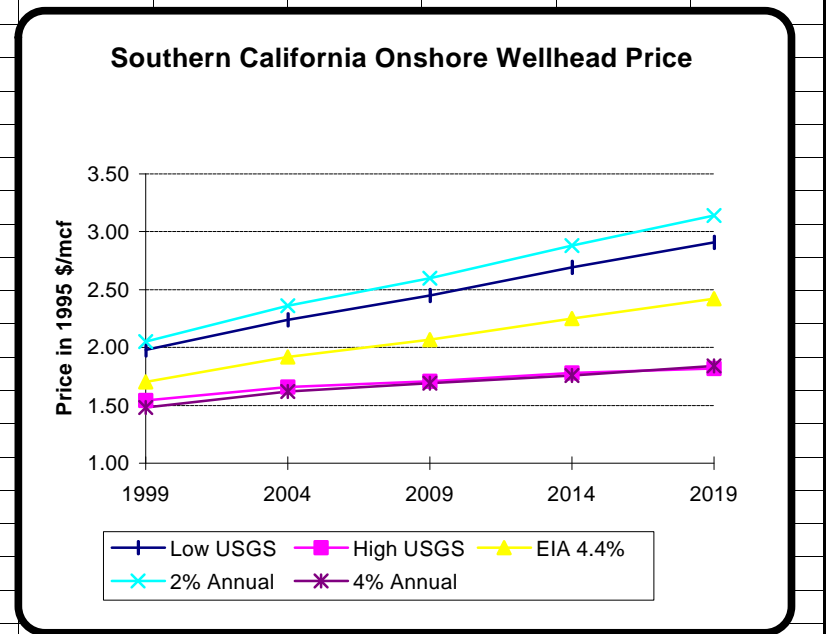
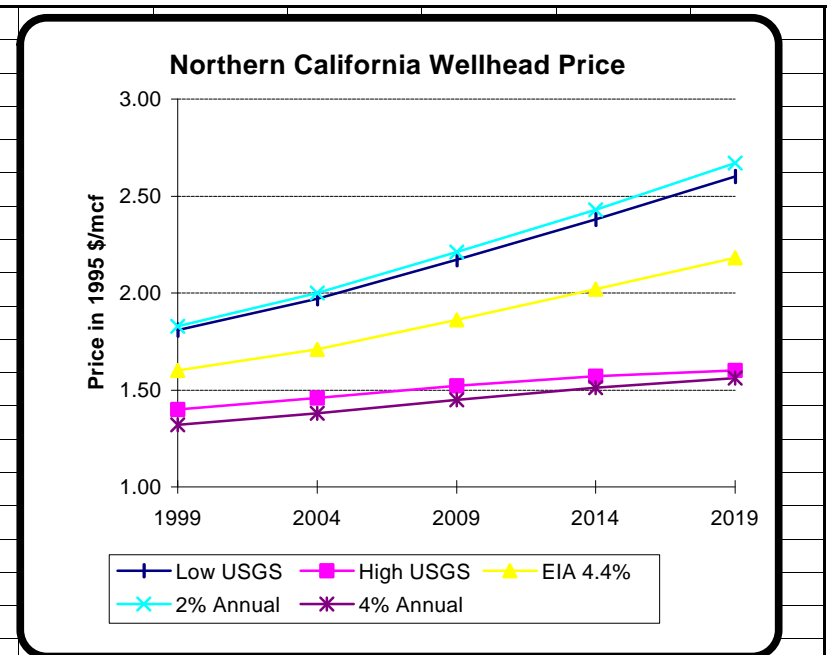
Southern Calif Onshore Production by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	169	247	220	209	200	219
High USGS	169	280	335	359	452	536
EIA 4.4%	169	237	183	169	162	155
2% Annual	169	231	216	214	195	219
4% Annual	169	253	253	227	262	272



Southern Calif State Offshore Production						
by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	7	2	8	11	13	13
High USGS	7	2	6	9	10	10
EIA 4.4%	7	2	5	9	11	12
2% Annual	7	2	7	12	13	14
4% Annual	7	2	4	8	9	9

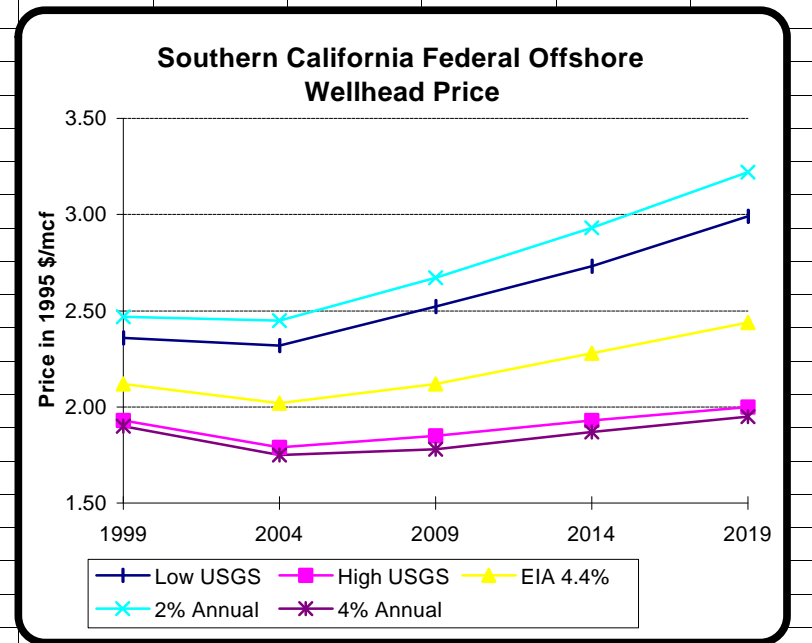
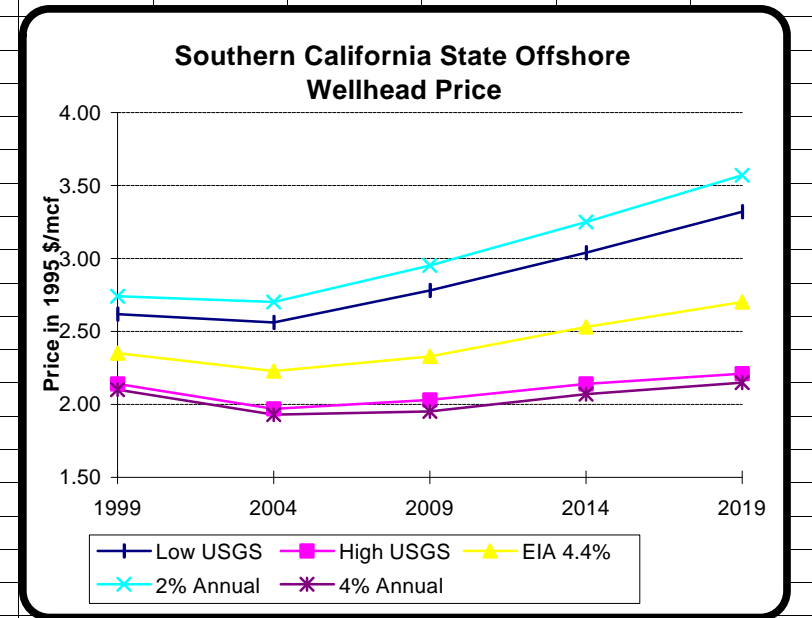
Southern Calif Federal Offshore Production						
by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	51	18	55	83	103	104
High USGS	51	15	42	60	72	74
EIA 4.4%	51	15	32	65	84	94
2% Annual	51	17	53	88	103	110
4% Annual	51	15	30	51	63	69



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Southern Calif State Offshore Production							
by Reference Case							
1995 \$/mcf							
	1999	2004	2009	2014	2019	Growth Rate	
Low USGS	2.62	2.56	2.78	3.04	3.32	1.2%	
High USGS	2.14	1.97	2.03	2.14	2.21	0.2%	
EIA 4.4%	2.35	2.23	2.33	2.53	2.70	0.7%	
2% Annual	2.74	2.70	2.95	3.25	3.57	1.3%	
4% Annual	2.10	1.93	1.95	2.07	2.15	0.1%	

Southern Calif Federal Offshore Production							
by Reference Case							
1995 \$/mcf							
	1999	2004	2009	2014	2019	Growth Rate	
Low USGS	2.36	2.32	2.52	2.73	2.99	1.2%	
High USGS	1.93	1.79	1.85	1.93	2.00	0.2%	
EIA 4.4%	2.12	2.02	2.12	2.28	2.44	0.7%	
2% Annual	2.47	2.45	2.67	2.93	3.22	1.3%	
4% Annual	1.90	1.75	1.78	1.87	1.95	0.1%	



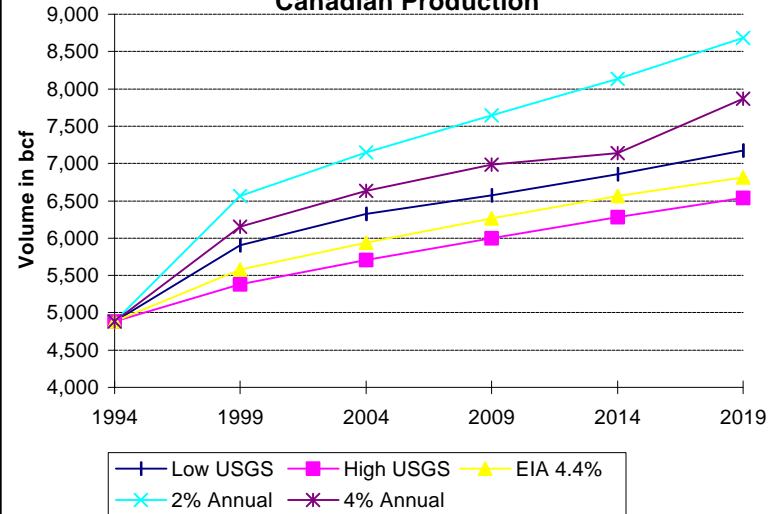
Canada

Canadian Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	4,885	5,901	6,327	6,571	6,860	7,174
High USGS	4,885	5,384	5,709	5,996	6,279	6,542
EIA 4.4%	4,885	5,580	5,939	6,262	6,563	6,817
2% Annual	4,885	6,561	7,144	7,642	8,130	8,683
4% Annual	4,885	6,151	6,630	6,982	7,142	7,871

Canadian Production

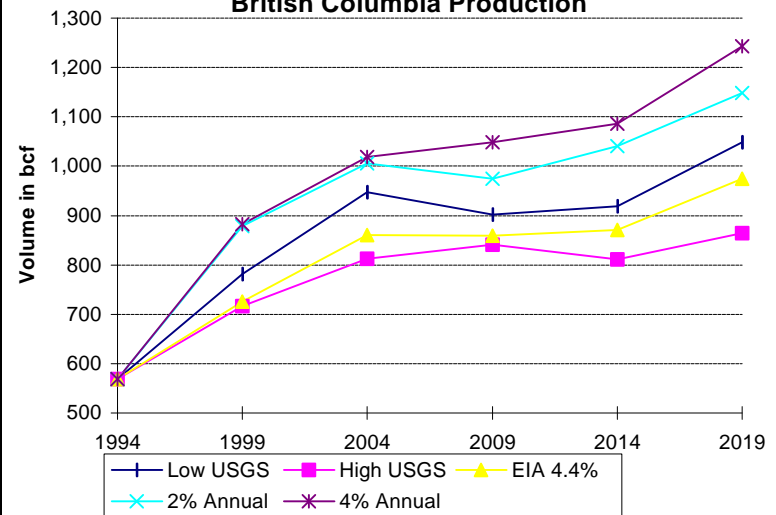


British Columbia Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	569	781	947	902	919	1,048
High USGS	569	716	813	841	811	864
EIA 4.4%	569	726	860	859	871	975
2% Annual	569	878	1,006	974	1,041	1,148
4% Annual	569	883	1,019	1,048	1,086	1,243

British Columbia Production



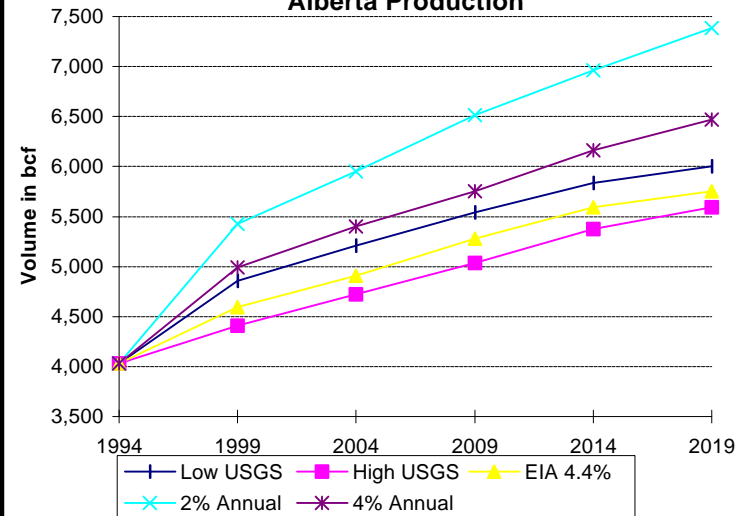
Canada

Alberta Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	4,034	4,860	5,206	5,540	5,836	6,005
High USGS	4,034	4,406	4,722	5,035	5,376	5,596
EIA 4.4%	4,034	4,592	4,906	5,278	5,595	5,754
2% Annual	4,034	5,424	5,949	6,514	6,960	7,382
4% Annual	4,034	4,992	5,404	5,755	6,164	6,471

Alberta Production

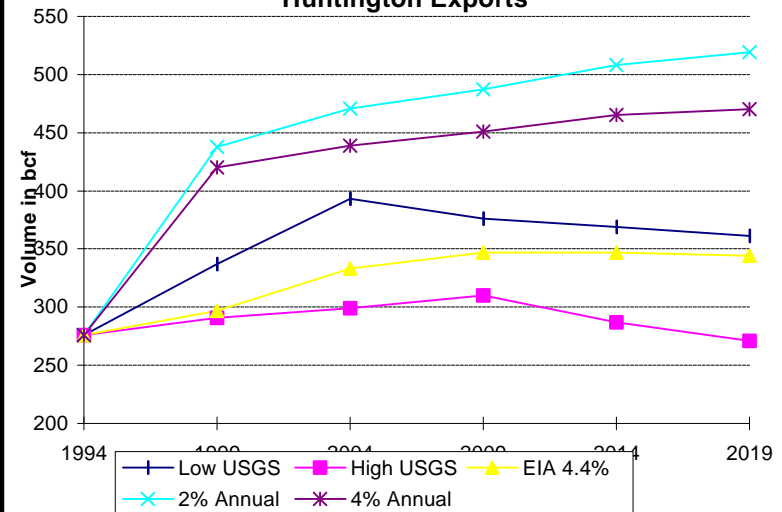


Huntington Export
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	276	337	393	376	369	361
High USGS	276	291	299	310	287	271
EIA 4.4%	276	297	333	347	347	344
2% Annual	276	438	471	487	508	519
4% Annual	276	420	439	451	465	470

Huntington Exports

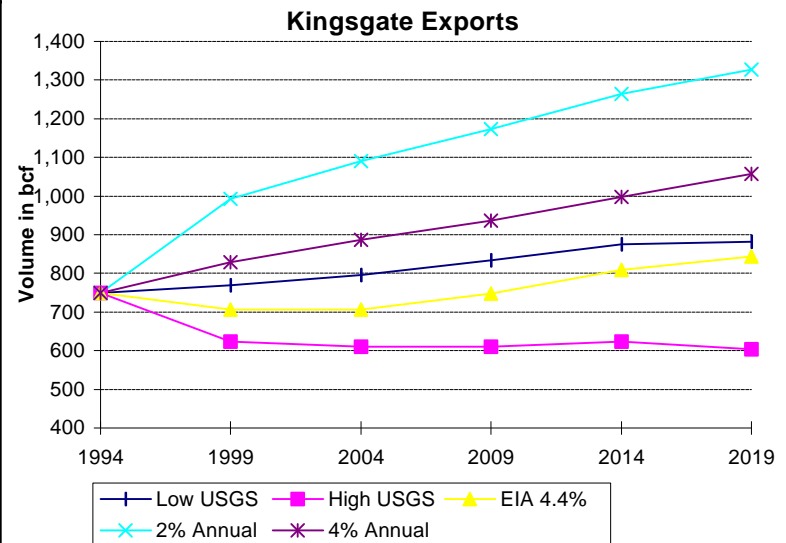


Canada

Kingsgate Export
by Reference Case

bcf

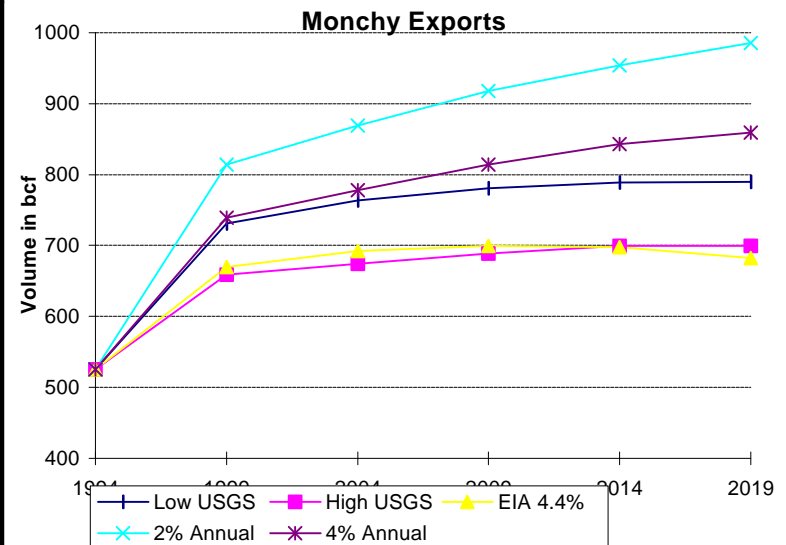
	1994	1999	2004	2009	2014	2019
Low USGS	749	770	796	834	875	882
High USGS	749	623	611	610	623	603
EIA 4.4%	749	707	707	747	809	844
2% Annual	749	993	1,090	1,174	1,265	1,327
4% Annual	749	829	886	936	998	1,057



Monchy Export
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	525	731	764	781	789	790
High USGS	525	659	674	689	700	700
EIA 4.4%	525	670	692	700	698	682
2% Annual	525	814	869	918	954	986
4% Annual	525	739	778	814	843	859

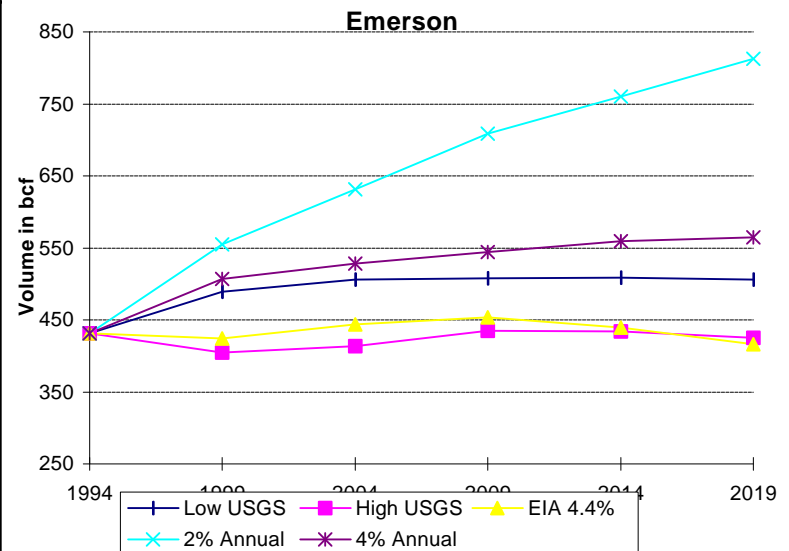


Canada

Emerson Export
by Reference Case

bcf

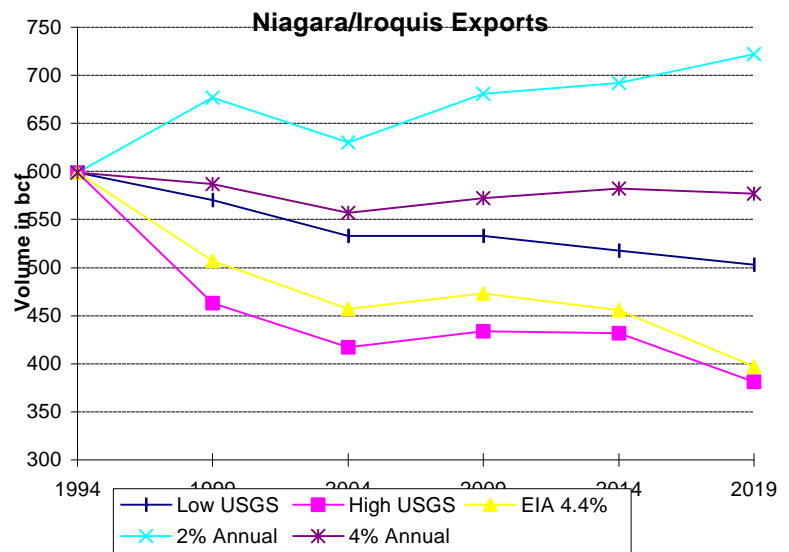
	1994	1999	2004	2009	2014	2019
Low USGS	431	489	506	508	509	506
High USGS	431	405	414	435	434	425
EIA 4.4%	431	424	444	454	439	416
2% Annual	431	555	631	709	760	813
4% Annual	431	507	528	544	559	565



Niagara/Iroquis Export
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	599	570	533	533	518	503
High USGS	599	463	417	434	432	381
EIA 4.4%	599	507	457	473	456	397
2% Annual	599	677	630	681	692	722
4% Annual	599	587	557	572	582	577

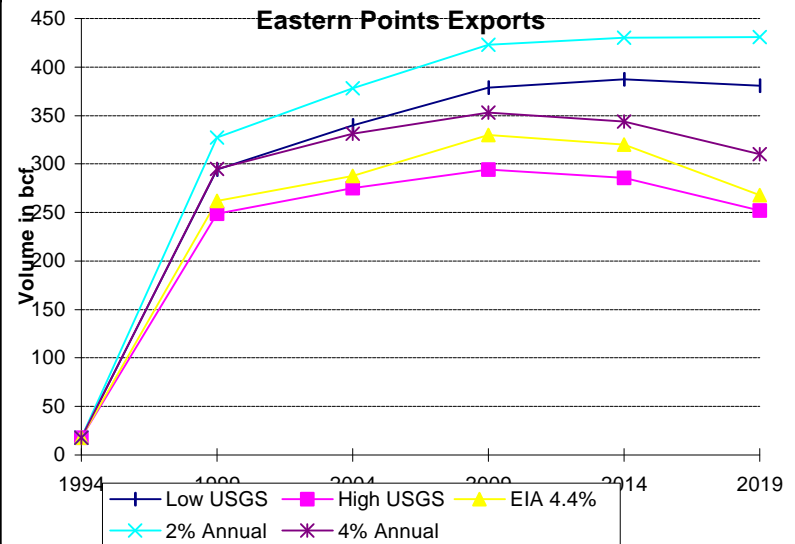


Canada

Eastern Points Export
by Reference Case

bcf

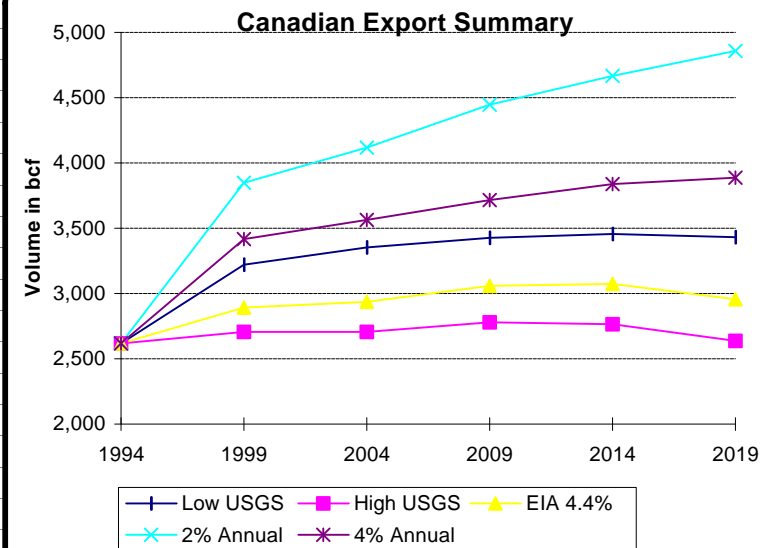
	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	18	294	340	379	387	381
High USGS	18	249	275	294	286	252
EIA 4.4%	18	262	288	330	320	268
2% Annual	18	327	378	423	430	431
4% Annual	18	295	331	353	344	310



Export Total
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	2,616	3,219	3,355	3,428	3,458	3,429
High USGS	2,616	2,705	2,706	2,781	2,767	2,635
EIA 4.4%	2,616	2,890	2,937	3,059	3,073	2,955
2% Annual	2,616	3,847	4,119	4,446	4,666	4,856
4% Annual	2,616	3,416	3,565	3,716	3,837	3,887



Canadian Average Wellhead Price
by Reference Case

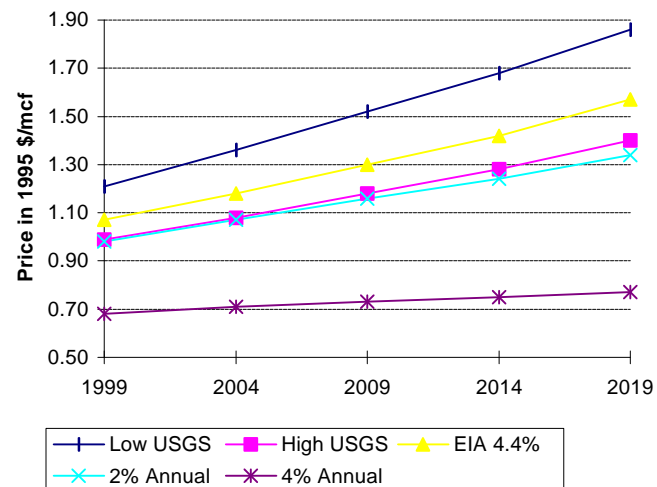
1995 \$/mcf

Growth

Rate

	1999	2004	2009	2014	2019	
Low USGS	1.21	1.36	1.52	1.68	1.86	2.2%
High USGS	0.99	1.08	1.18	1.28	1.40	1.7%
EIA 4.4%	1.07	1.18	1.30	1.42	1.57	1.9%
2% Annual	0.98	1.07	1.16	1.24	1.34	1.6%
4% Annual	0.68	0.71	0.73	0.75	0.77	0.6%

Canadian Ave Wellhead Price



British Columbia Wellhead Price
by Reference Case

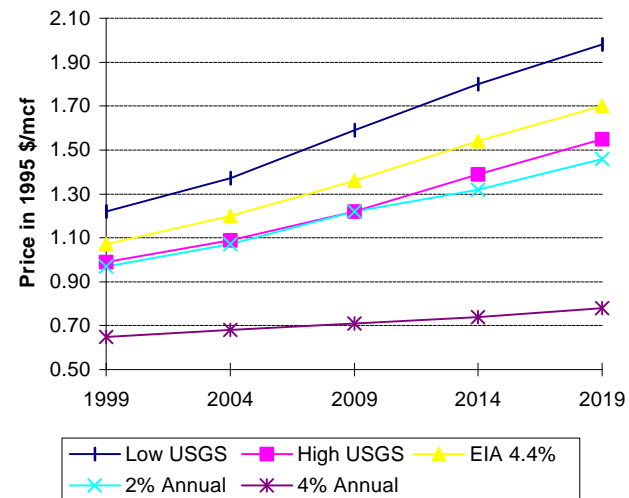
1995 \$/mcf

Growth

Rate

	1999	2004	2009	2014	2019	
Low USGS	1.22	1.37	1.59	1.80	1.98	2.5%
High USGS	0.99	1.09	1.22	1.39	1.55	2.3%
EIA 4.4%	1.07	1.20	1.36	1.54	1.70	2.3%
2% Annual	0.97	1.07	1.22	1.32	1.46	2.1%
4% Annual	0.65	0.68	0.71	0.74	0.78	0.9%

British Columbia Wellhead Price



Alberta Wellhead Price
by Reference Case

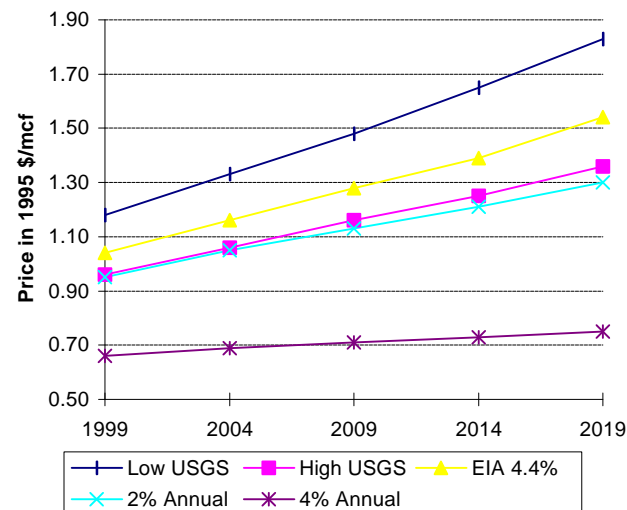
1995 \$/mcf

Growth

Rate

	1999	2004	2009	2014	2019	
Low USGS	1.18	1.33	1.48	1.65	1.83	2.2%
High USGS	0.96	1.06	1.16	1.25	1.36	1.8%
EIA 4.4%	1.04	1.16	1.28	1.39	1.54	2.0%
2% Annual	0.95	1.05	1.13	1.21	1.30	1.6%
4% Annual	0.66	0.69	0.71	0.73	0.75	0.6%

Alberta Wellhead Price



Huntington Export Price
by Reference Case

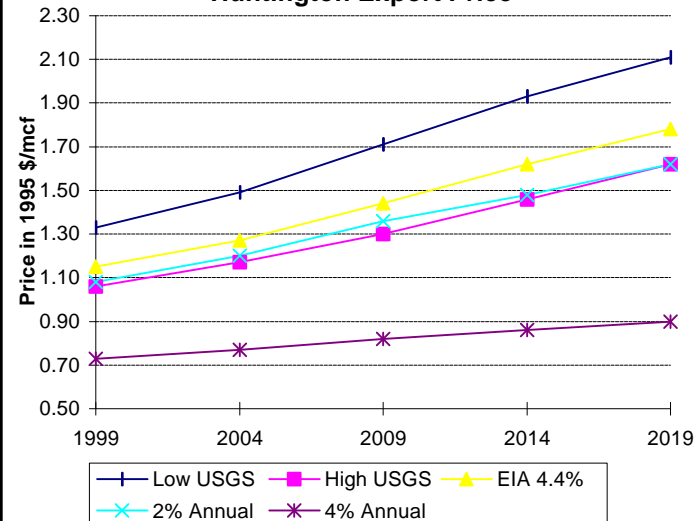
1995 \$/mcf

Growth

Rate

	1999	2004	2009	2014	2019	
Low USGS	1.33	1.49	1.71	1.93	2.11	2.3%
High USGS	1.06	1.17	1.30	1.46	1.62	2.1%
EIA 4.4%	1.15	1.27	1.44	1.62	1.78	2.2%
2% Annual	1.08	1.20	1.36	1.48	1.62	2.0%
4% Annual	0.73	0.77	0.82	0.86	0.90	1.1%

Huntington Export Price



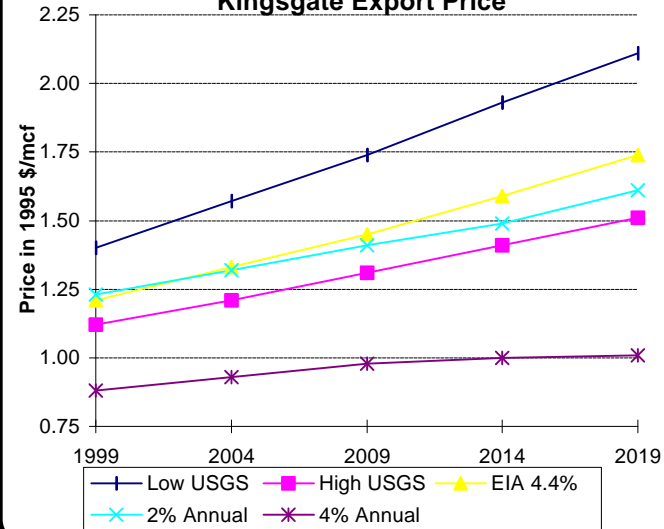
Kingsgate Export Price
by Reference Case

1995 \$/mcf

Growth
Rate

	1999	2004	2009	2014	2019	
Low USGS	1.40	1.57	1.74	1.93	2.11	2.1%
High USGS	1.12	1.21	1.31	1.41	1.51	1.5%
EIA 4.4%	1.21	1.33	1.45	1.59	1.74	1.8%
2% Annual	1.23	1.32	1.41	1.49	1.61	1.4%
4% Annual	0.88	0.93	0.98	1.00	1.01	0.7%

Kingsgate Export Price



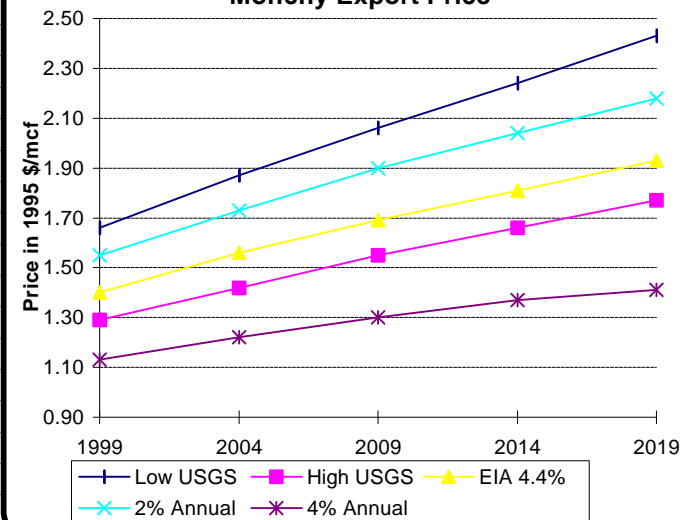
Monchy Export Price
by Reference Case

1995 \$/mcf

Growth
Rate

	1999	2004	2009	2014	2019	
Low USGS	1.66	1.87	2.06	2.24	2.43	1.9%
High USGS	1.29	1.42	1.55	1.66	1.77	1.6%
EIA 4.4%	1.40	1.56	1.69	1.81	1.93	1.6%
2% Annual	1.55	1.73	1.90	2.04	2.18	1.7%
4% Annual	1.13	1.22	1.30	1.37	1.41	1.1%

Monchy Export Price



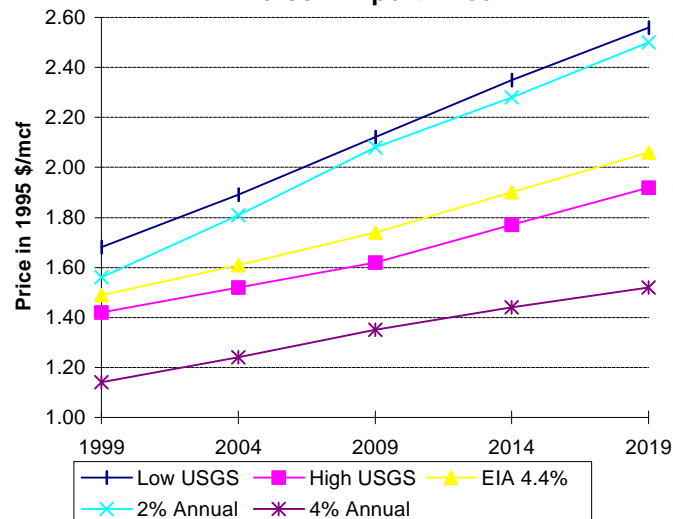
Emerson Export Price
by Reference Case

1995 \$/mcf

Growth

	1999	2004	2009	2014	2019	Rate
Low USGS	1.68	1.89	2.12	2.35	2.56	2.1%
High USGS	1.42	1.52	1.62	1.77	1.92	1.5%
EIA 4.4%	1.49	1.61	1.74	1.90	2.06	1.6%
2% Annual	1.56	1.81	2.08	2.28	2.50	2.4%
4% Annual	1.14	1.24	1.35	1.44	1.52	1.4%

Emerson Export Price

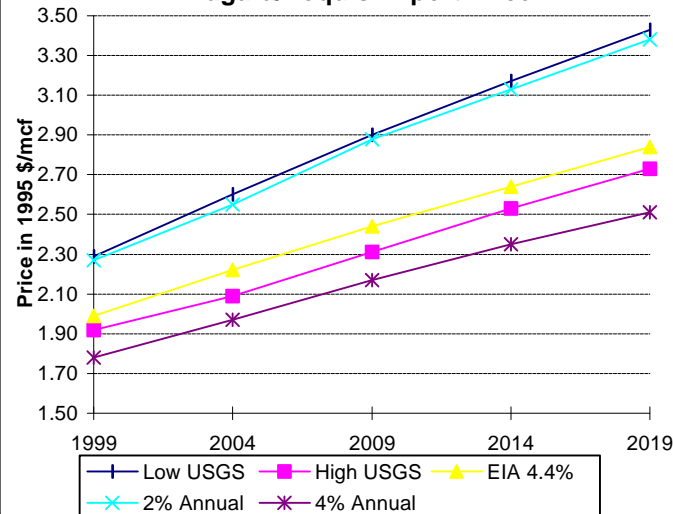
Niagara/Iroquis Export Price
by Reference Case

1995 \$/mcf

Growth

	1999	2004	2009	2014	2019	Rate
Low USGS	2.29	2.60	2.90	3.17	3.43	2.0%
High USGS	1.92	2.09	2.31	2.53	2.73	1.8%
EIA 4.4%	1.99	2.22	2.44	2.64	2.84	1.8%
2% Annual	2.27	2.55	2.88	3.13	3.38	2.0%
4% Annual	1.78	1.97	2.17	2.35	2.51	1.7%

Niagara/Iroquis Export Price



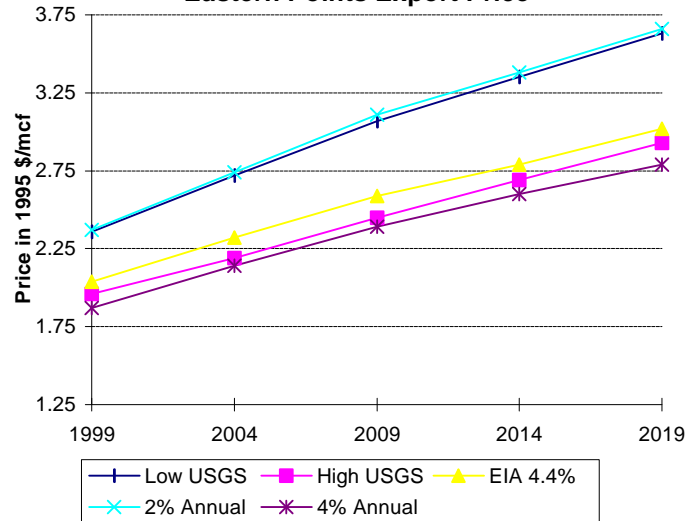
Eastern Points Export Price
by Reference Case

1995 \$/mcf

Growth

	1999	2004	2009	2014	2019	Rate
Low USGS	2.36	2.72	3.07	3.35	3.63	2.2%
High USGS	1.96	2.19	2.45	2.69	2.93	2.0%
EIA 4.4%	2.04	2.32	2.59	2.79	3.02	2.0%
2% Annual	2.37	2.74	3.11	3.38	3.66	2.2%
4% Annual	1.87	2.14	2.39	2.60	2.79	2.0%

Eastern Points Export Price



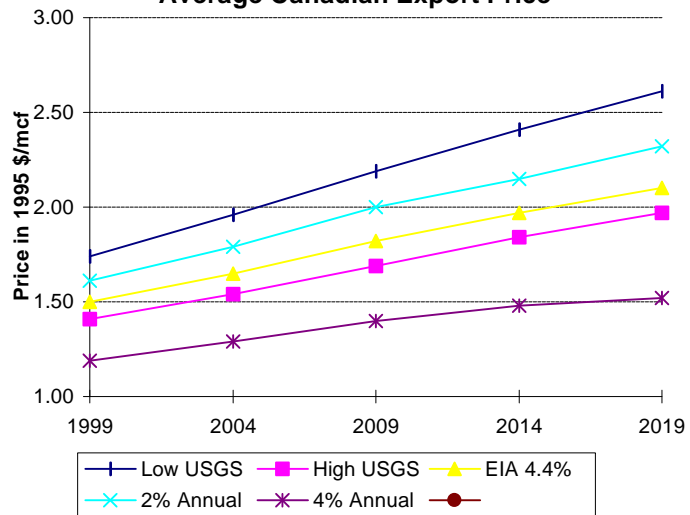
Average Canadian Export Price
by Reference Case

1995 \$/mcf

Growth

	1999	2004	2009	2014	2019	Rate
Low USGS	1.74	1.96	2.19	2.41	2.61	2.0%
High USGS	1.41	1.54	1.69	1.84	1.97	1.7%
EIA 4.4%	1.50	1.65	1.82	1.97	2.10	1.7%
2% Annual	1.61	1.79	2.00	2.15	2.32	1.8%
4% Annual	1.19	1.29	1.40	1.48	1.52	1.2%

Average Canadian Export Price

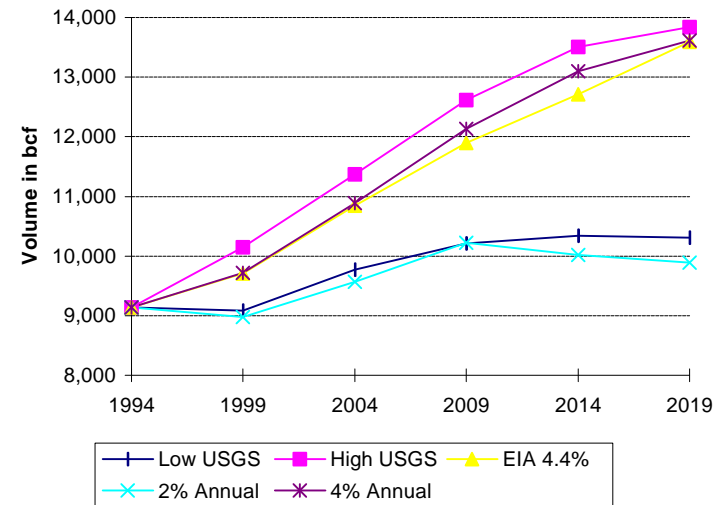


Gulf Production Summary
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	9,135	9,087	9,768	10,214	10,337	10,303
High USGS	9,135	10,145	11,375	12,616	13,501	13,837
EIA 4.4%	9,135	9,709	10,839	11,895	12,714	13,590
2% Annual	9,135	8,982	9,571	10,218	10,023	9,886
4% Annual	9,135	9,720	10,892	12,134	13,094	13,613

Gulf Production Summary

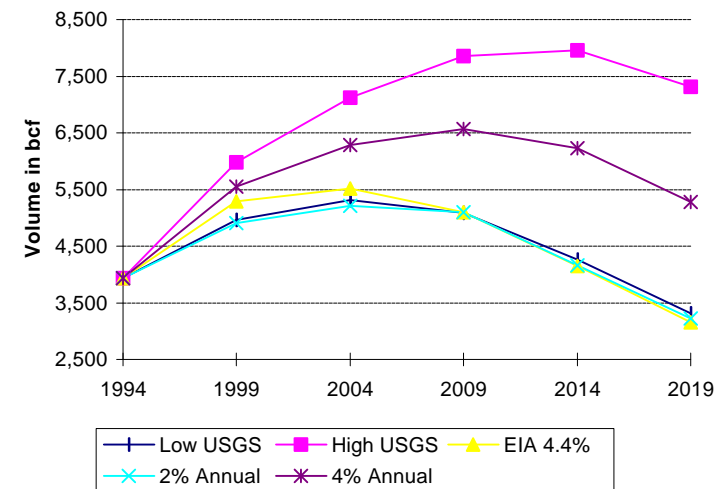


Gulf Conventional Onshore Production
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	3,934	4,960	5,315	5,084	4,264	3,311
High USGS	3,934	5,979	7,121	7,860	7,961	7,318
EIA 4.4%	3,934	5,291	5,515	5,104	4,152	3,154
2% Annual	3,934	4,905	5,209	5,095	4,165	3,224
4% Annual	3,934	5,546	6,287	6,567	6,230	5,277

Gulf Conventional Onshore Production

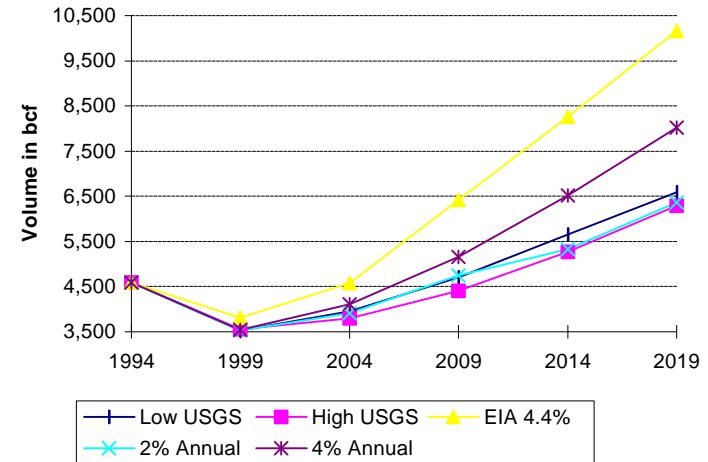


**Gulf Conventional Offshore Production
by Reference Case**

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	4,593	3,535	3,957	4,710	5,657	6,585
High USGS	4,593	3,560	3,798	4,405	5,265	6,295
EIA 4.4%	4,593	3,808	4,580	6,418	8,257	10,167
2% Annual	4,593	3,527	3,909	4,745	5,330	6,360
4% Annual	4,593	3,539	4,115	5,161	6,513	8,017

Gulf Conventional Offshore Production

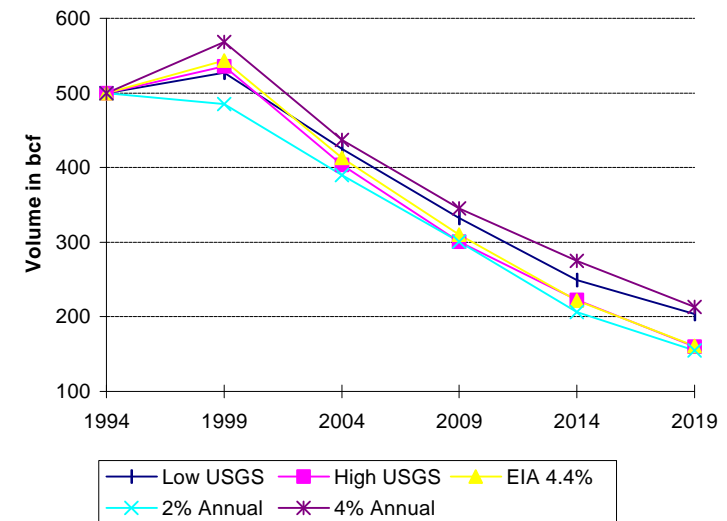


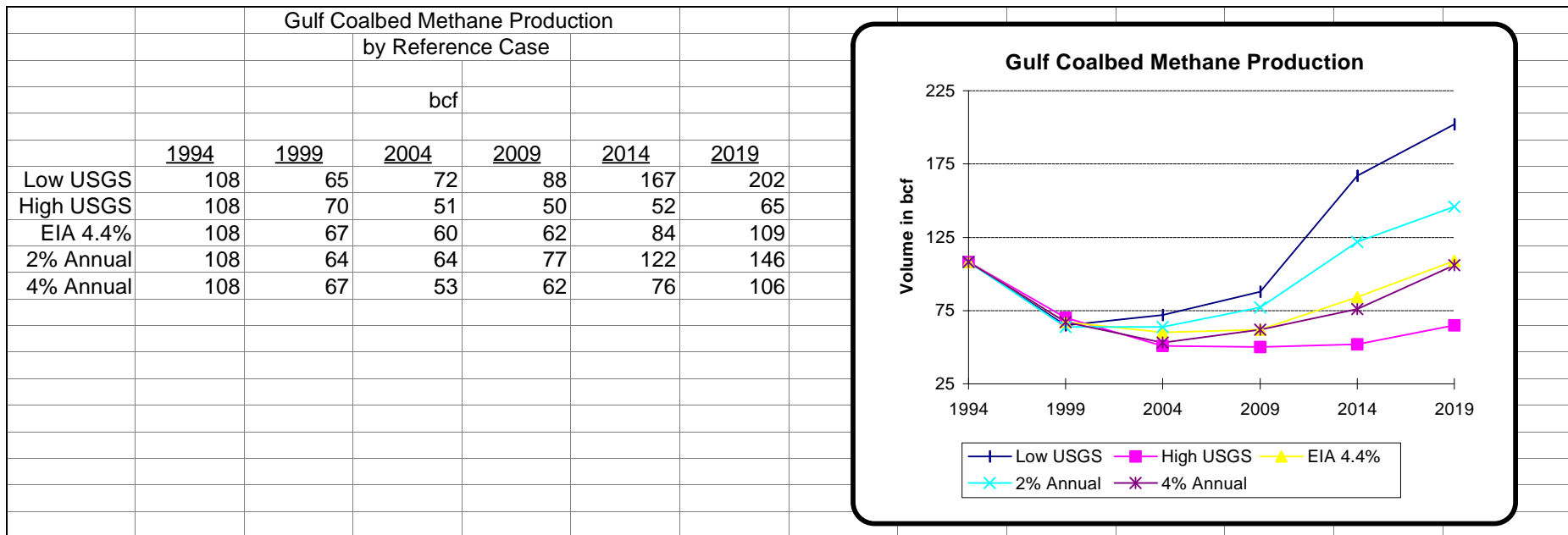
**Gulf Tight Sands Production
by Reference Case**

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	500	527	425	332	249	204
High USGS	500	536	404	301	223	160
EIA 4.4%	500	543	413	310	222	161
2% Annual	500	485	390	301	206	155
4% Annual	500	568	437	345	275	213

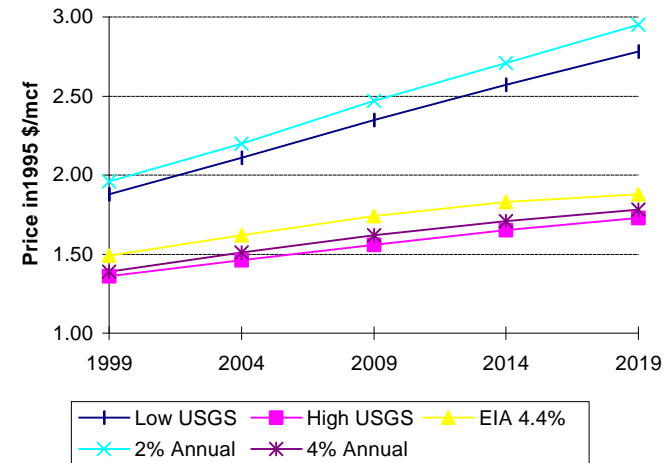
Gulf Tight Sands Production





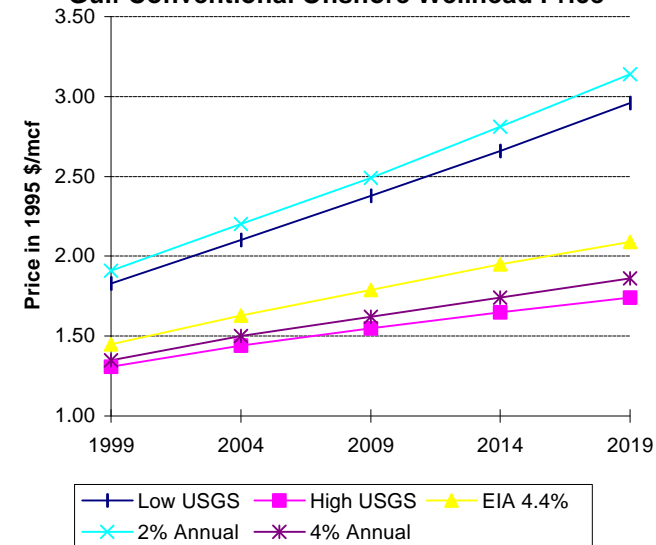
Gulf Average Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.88	2.11	2.35	2.57	2.78	2.0%
High USGS	1.36	1.46	1.56	1.65	1.73	1.2%
EIA 4.4%	1.49	1.62	1.74	1.83	1.88	1.2%
2% Annual	1.96	2.20	2.47	2.71	2.95	2.1%
4% Annual	1.39	1.51	1.62	1.71	1.78	1.2%

Gulf Average Wellhead Price



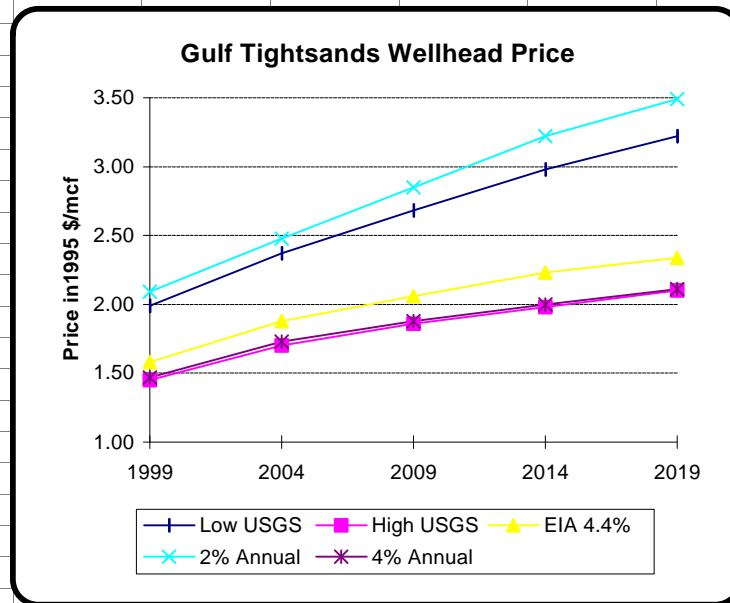
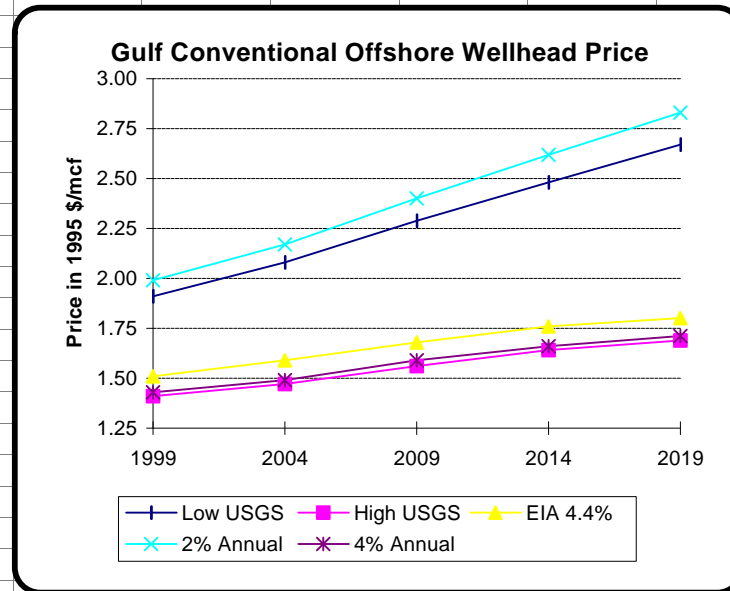
Gulf Conventional Onshore Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.83	2.10	2.38	2.66	2.96	2.4%
High USGS	1.31	1.44	1.55	1.65	1.74	1.4%
EIA 4.4%	1.45	1.63	1.79	1.95	2.09	1.8%
2% Annual	1.91	2.20	2.49	2.81	3.14	2.5%
4% Annual	1.35	1.50	1.62	1.74	1.86	1.6%

Gulf Conventional Onshore Wellhead Price



Gulf Conventional Offshore Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.91	2.08	2.29	2.48	2.67	1.7%
High USGS	1.41	1.47	1.56	1.64	1.69	0.9%
EIA 4.4%	1.51	1.59	1.68	1.76	1.80	0.9%
2% Annual	1.99	2.17	2.40	2.62	2.83	1.8%
4% Annual	1.43	1.49	1.59	1.66	1.71	0.9%

Gulf Tight Sands Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.99	2.37	2.68	2.98	3.22	2.4%
High USGS	1.45	1.70	1.86	1.98	2.10	1.9%
EIA 4.4%	1.58	1.88	2.06	2.23	2.34	2.0%
2% Annual	2.09	2.48	2.85	3.22	3.49	2.6%
4% Annual	1.47	1.73	1.88	2.00	2.11	1.8%

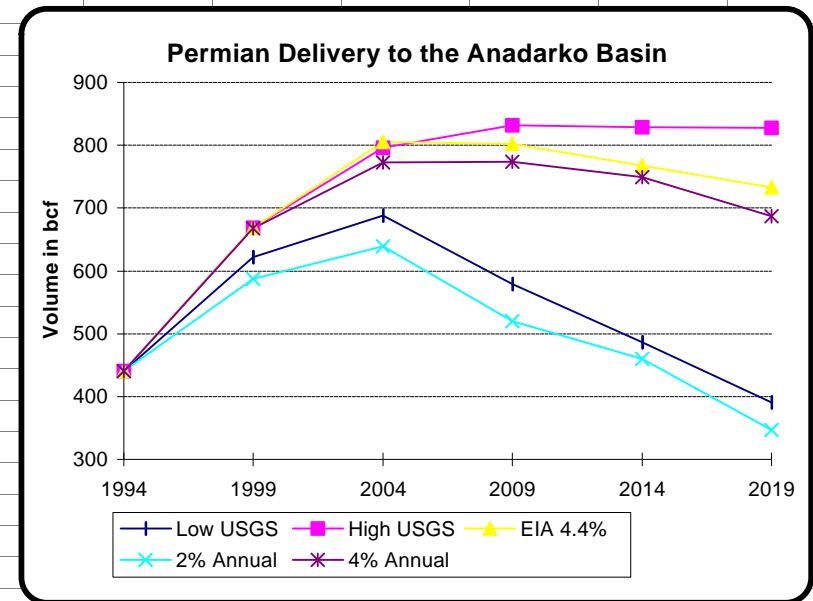
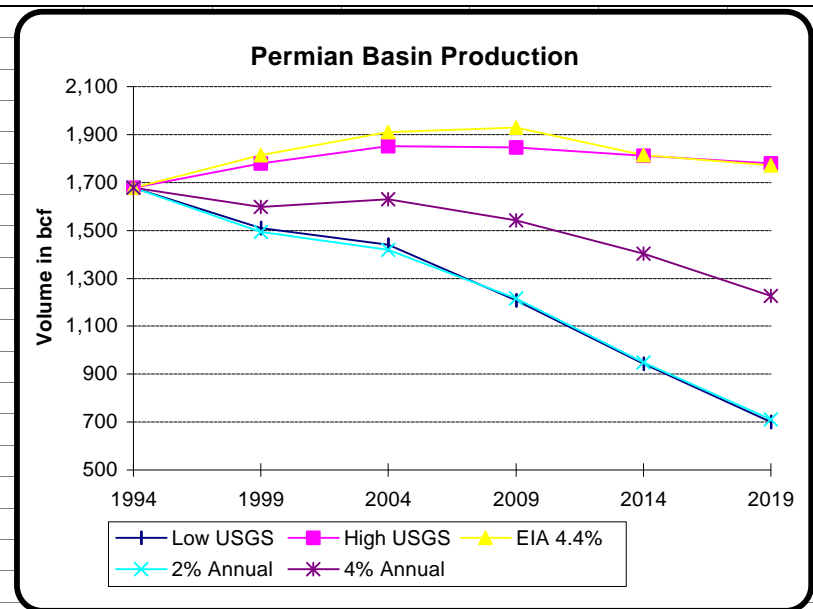


Year	Low USGS	High USGS	EIA 4.4%	2% Annual	4% Annual
1999	2.55	2.00	2.15	2.65	2.00
2004	2.50	1.90	2.00	2.65	1.90
2009	2.75	1.95	2.10	2.90	1.95
2014	2.85	2.05	2.15	3.05	2.05
2019	3.10	2.10	2.25	3.40	2.10

Permian

Permian Conventional Production by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	1,677	1,509	1,441	1,209	943	700
High USGS	1,677	1,780	1,852	1,845	1,812	1,780
EIA 4.4%	1,677	1,814	1,910	1,928	1,813	1,772
2% Annual	1,677	1,494	1,419	1,215	950	710
4% Annual	1,677	1,599	1,631	1,542	1,404	1,226

Permian Delivery to the Anadarko Basin by Reference Case						
	bcf					
	1994	1999	2004	2009	2014	2019
Low USGS	441	622	688	579	486	391
High USGS	441	669	796	832	829	828
EIA 4.4%	441	669	805	802	768	733
2% Annual	441	587	639	520	460	347
4% Annual	441	668	773	774	749	687



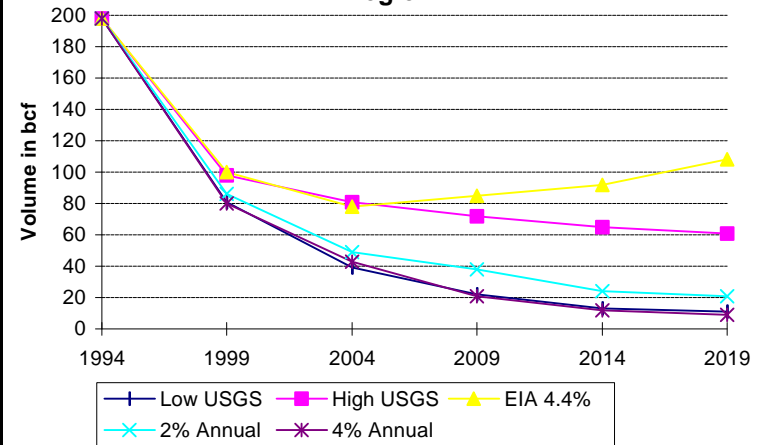
Permian

Permian to SW Desert
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	198	81	39	22	13	11
High USGS	198	98	81	72	65	61
EIA 4.4%	198	100	78	85	92	108
2% Annual	198	86	49	38	24	21
4% Annual	198	80	43	21	12	9

Permian Delivery to the SW Desert Demand
Region

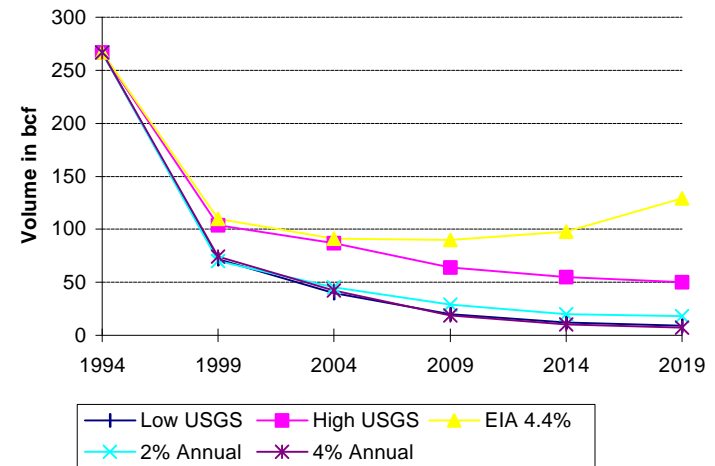


Permian to Blythe
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	267	72	40	20	12	9
High USGS	267	104	87	64	55	50
EIA 4.4%	267	110	91	90	98	129
2% Annual	267	70	45	29	20	18
4% Annual	267	74	42	19	10	7

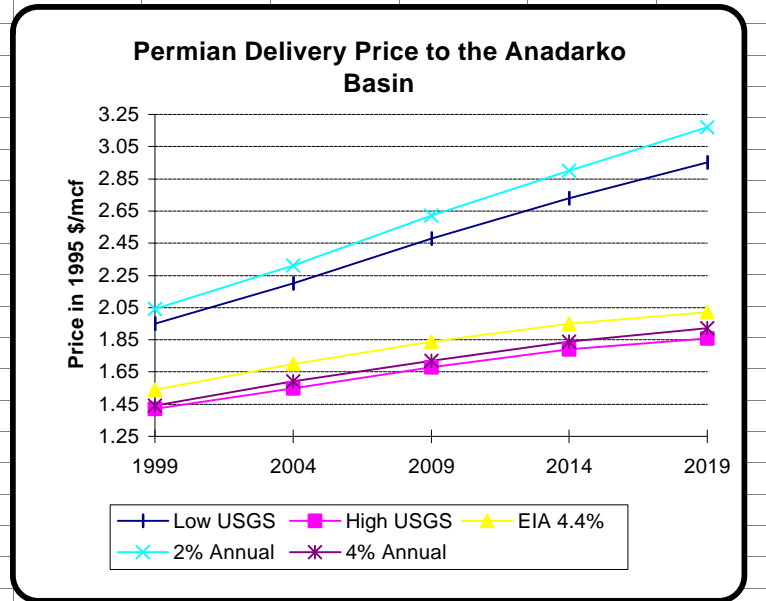
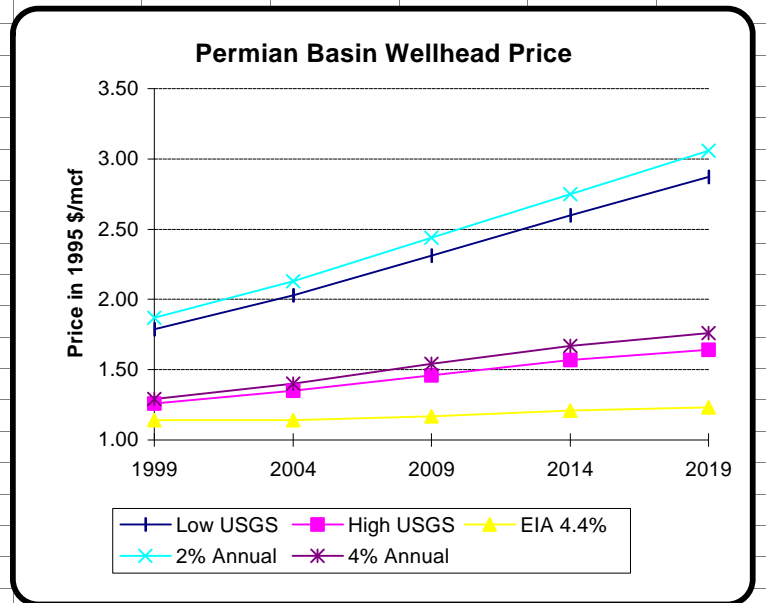
Permian Delivery to SoCal Gas at Blythe



Permian

Permian Conventional Production by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.79	2.03	2.31	2.60	2.87	2.4%
High USGS	1.26	1.35	1.46	1.57	1.64	1.3%
EIA 4.4%	1.14	1.14	1.17	1.21	1.23	0.4%
2% Annual	1.87	2.13	2.44	2.75	3.06	2.5%
4% Annual	1.29	1.40	1.54	1.67	1.76	1.6%

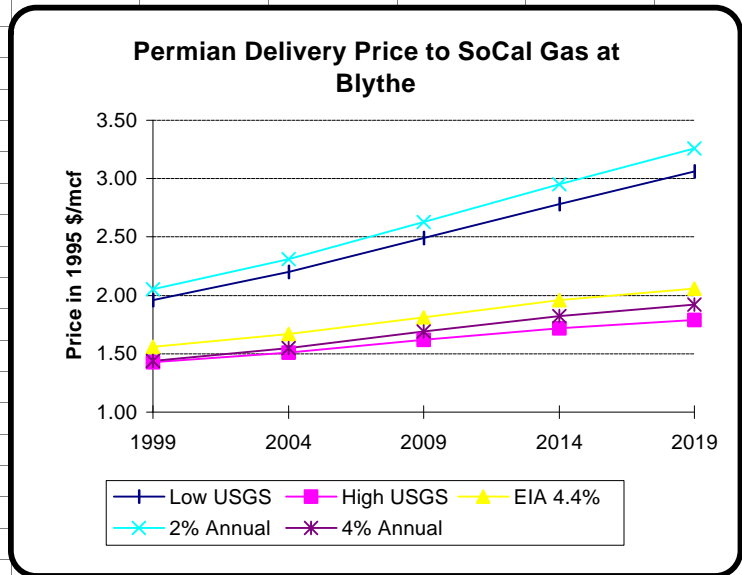
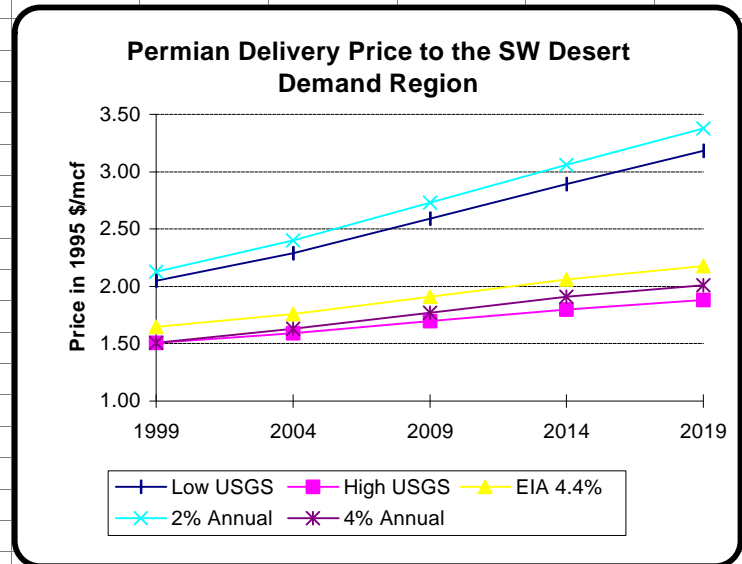
Permian Delivery to the Anadarko Basin by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.95	2.20	2.48	2.73	2.95	2.1%
High USGS	1.42	1.55	1.68	1.79	1.86	1.4%
EIA 4.4%	1.54	1.70	1.84	1.95	2.02	1.4%
2% Annual	2.04	2.31	2.62	2.90	3.17	2.2%
4% Annual	1.44	1.59	1.72	1.84	1.92	1.4%



Permian

Permian to SW Desert by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	2.05	2.29	2.59	2.89	3.18	2.2%
High USGS	1.51	1.59	1.70	1.80	1.88	1.1%
EIA 4.4%	1.65	1.76	1.91	2.06	2.18	1.4%
2% Annual	2.13	2.40	2.73	3.06	3.38	2.3%
4% Annual	1.51	1.63	1.77	1.91	2.01	1.4%

Permian to Blythe by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.96	2.20	2.49	2.78	3.06	2.3%
High USGS	1.43	1.51	1.62	1.72	1.79	1.1%
EIA 4.4%	1.56	1.67	1.81	1.96	2.06	1.4%
2% Annual	2.05	2.31	2.63	2.95	3.26	2.3%
4% Annual	1.44	1.55	1.69	1.82	1.92	1.4%



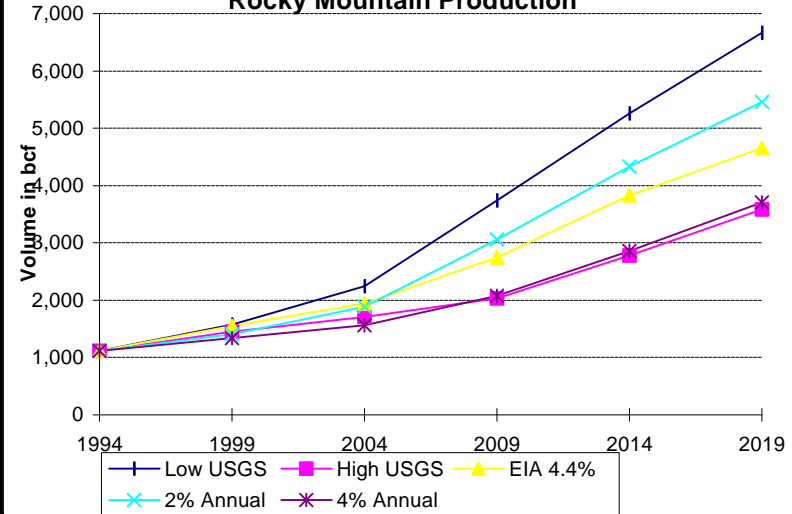
Rocky Mtns

Rocky Mtn Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	1,121	1,579	2,246	3,740	5,261	6,660
High USGS	1,121	1,446	1,706	2,033	2,785	3,588
EIA 4.4%	1,121	1,555	1,941	2,751	3,828	4,656
2% Annual	1,121	1,402	1,889	3,055	4,336	5,457
4% Annual	1,121	1,335	1,558	2,079	2,857	3,703

Rocky Mountain Production

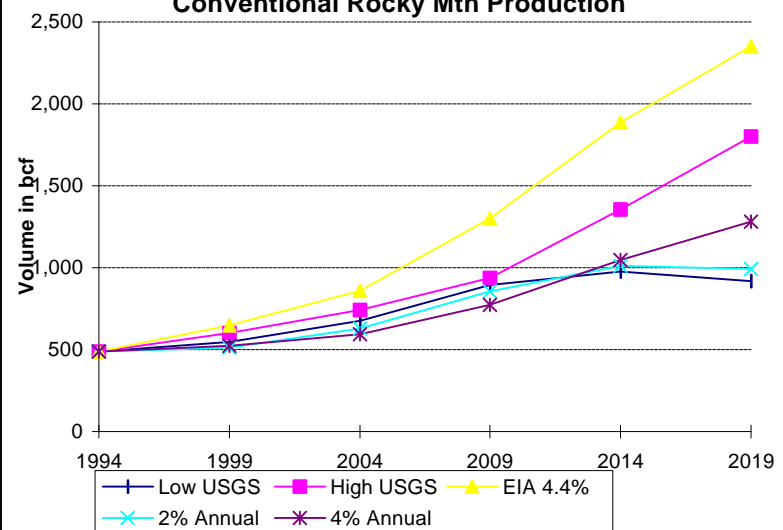


Conventional Rocky Mtn Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	488	546	676	894	977	917
High USGS	488	601	741	936	1,355	1,802
EIA 4.4%	488	648	858	1,301	1,887	2,352
2% Annual	488	513	628	856	1,012	994
4% Annual	488	523	594	775	1,045	1,282

Conventional Rocky Mtn Production



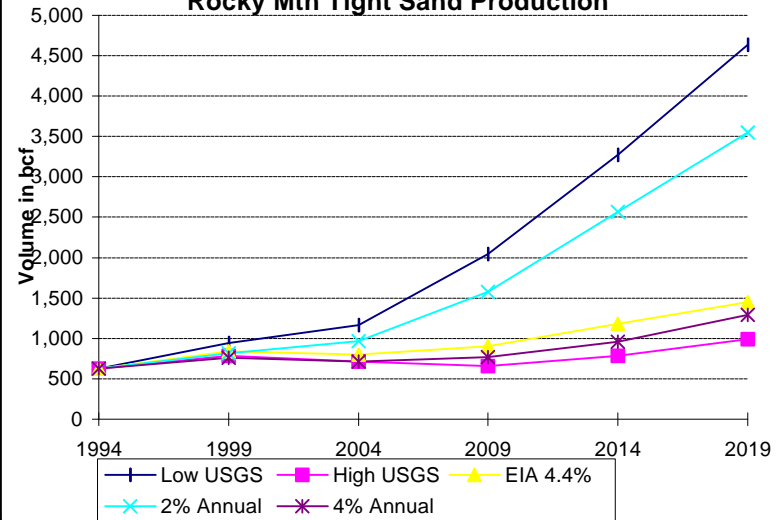
Rocky Mtns

Tight Sands Rocky Mtn Production
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	628	943	1,167	2,042	3,272	4,634
High USGS	628	786	711	659	782	992
EIA 4.4%	628	840	799	904	1,182	1,451
2% Annual	628	819	966	1,580	2,567	3,546
4% Annual	628	757	713	768	957	1,290

Rocky Mtn Tight Sand Production

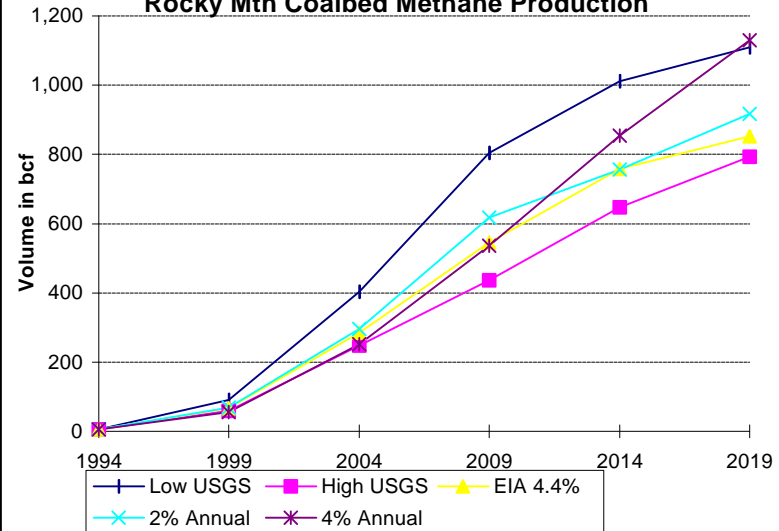


Coalbed Methane Rocky Mtn Production
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	5	90	403	805	1,012	1,109
High USGS	5	60	248	437	648	794
EIA 4.4%	5	67	284	546	759	853
2% Annual	5	69	296	618	757	917
4% Annual	5	55	251	536	855	1,130

Rocky Mtn Coalbed Methane Production



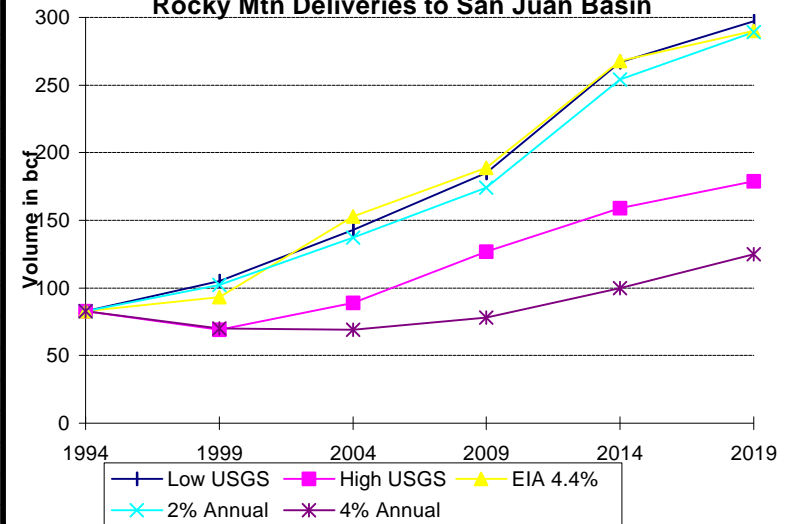
Rocky Mtns

Rocky Mtn to San Juan by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	83	105	143	185	267	297
High USGS	83	69	89	127	159	179
EIA 4.4%	83	93	153	189	268	290
2% Annual	83	102	137	174	254	289
4% Annual	83	70	69	78	100	125

Rocky Mtn Deliveries to San Juan Basin

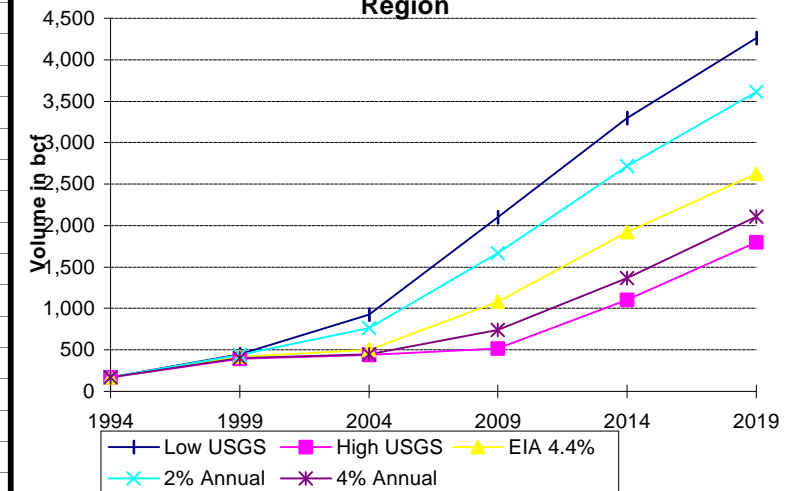


Rocky Mtn to WNC by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	173	449	929	2,097	3,293	4,260
High USGS	173	394	437	515	1,105	1,795
EIA 4.4%	173	419	498	1,078	1,924	2,621
2% Annual	173	441	761	1,670	2,719	3,613
4% Annual	173	402	451	741	1,367	2,104

Rocky Mtn Deliveries to the WNC Demand Region



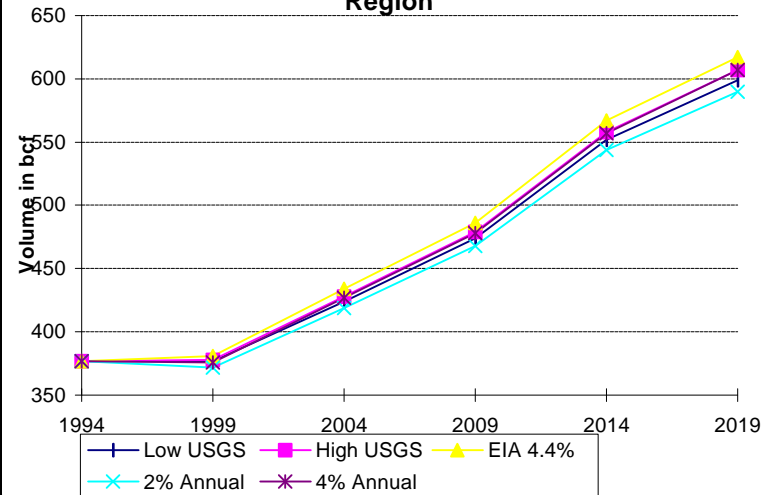
Rocky Mtns

Rocky Mtn to Rocky Mtn Demand
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	377	377	424	474	552	599
High USGS	377	378	428	479	558	607
EIA 4.4%	377	381	434	486	567	617
2% Annual	377	372	419	468	544	590
4% Annual	377	376	427	478	557	607

Rocky Mtn Deliveries to the Rocky Mtn Demand
Region

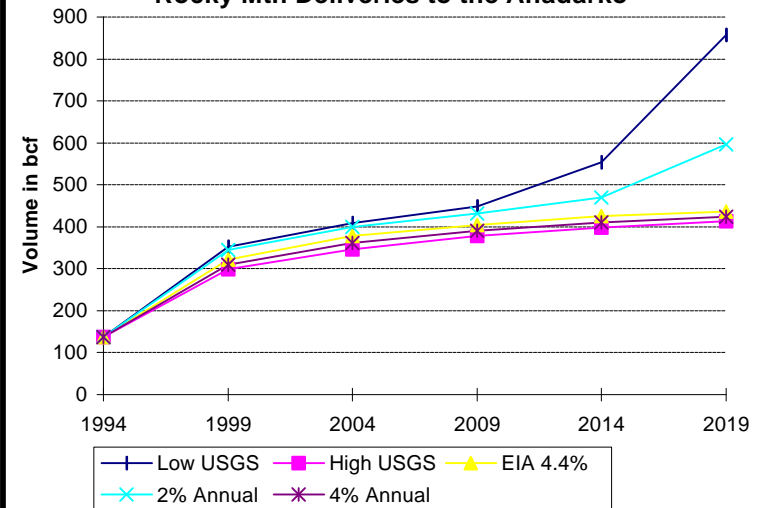


Rocky Mtns to Anadarko
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	138	352	409	448	554	858
High USGS	138	299	347	378	398	413
EIA 4.4%	138	322	378	405	425	437
2% Annual	138	344	399	431	470	597
4% Annual	138	309	361	390	410	424

Rocky Mtn Deliveries to the Anadarko

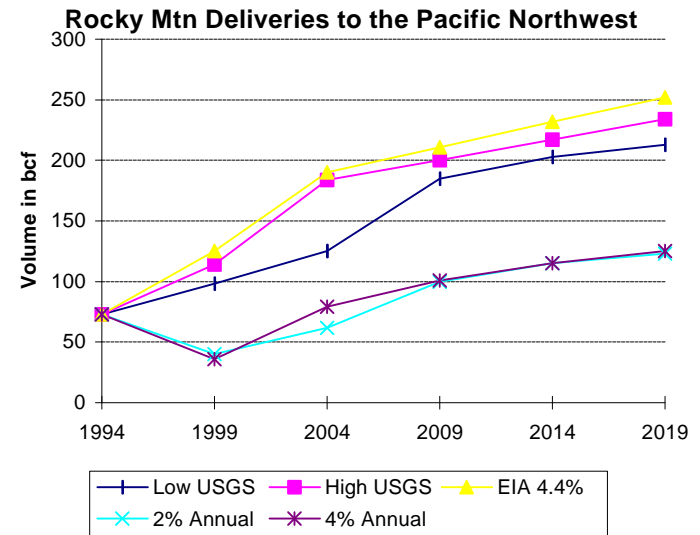


Rocky Mtns

Rocky Mtns to Pacific Northwest
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	73	98	125	185	203	213
High USGS	73	114	184	200	217	234
EIA 4.4%	73	125	190	211	232	252
2% Annual	73	40	62	100	115	123
4% Annual	73	36	79	101	115	125



Rocky Mtns

Rocky Mtn Average Wellhead Price
by Reference Case

1995 \$/mcf

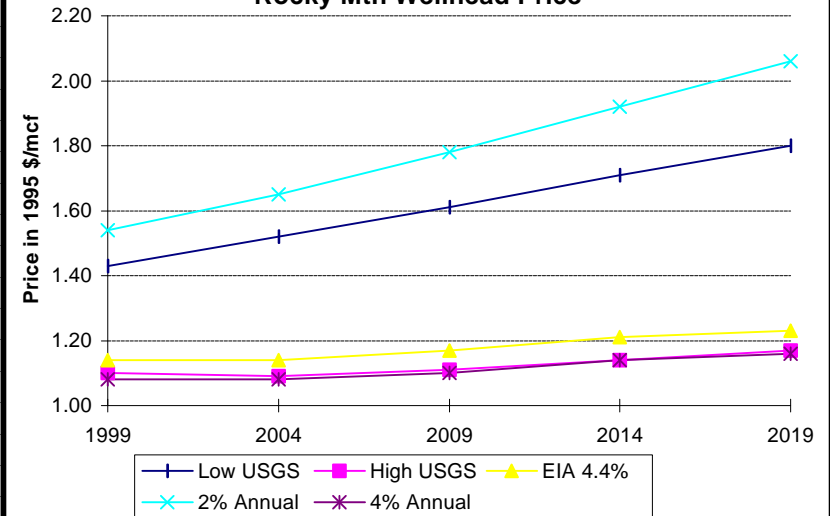
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.43	1.52	1.61	1.71	1.80	1.2%
High USGS	1.10	1.09	1.11	1.14	1.17	0.3%
EIA 4.4%	1.14	1.14	1.17	1.21	1.23	0.4%
2% Annual	1.54	1.65	1.78	1.92	2.06	1.5%
4% Annual	1.08	1.08	1.10	1.14	1.16	0.4%

Conventional Rocky Mtn Wellhead Price
by Reference Case

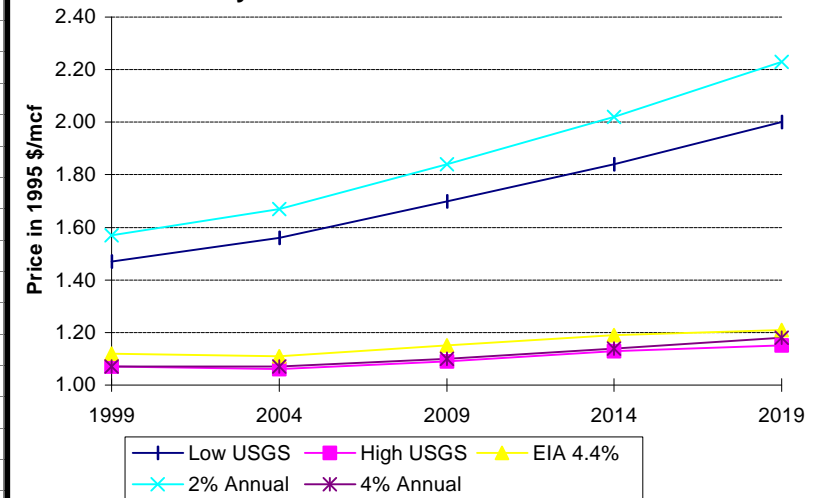
1995 \$/mcf

	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.47	1.56	1.70	1.84	2.00	1.6%
High USGS	1.07	1.06	1.09	1.13	1.15	0.4%
EIA 4.4%	1.12	1.11	1.15	1.19	1.21	0.4%
2% Annual	1.57	1.67	1.84	2.02	2.23	1.8%
4% Annual	1.07	1.07	1.10	1.14	1.18	0.5%

Rocky Mtn Wellhead Price



Rocky Mtn Conventional Wellhead Price

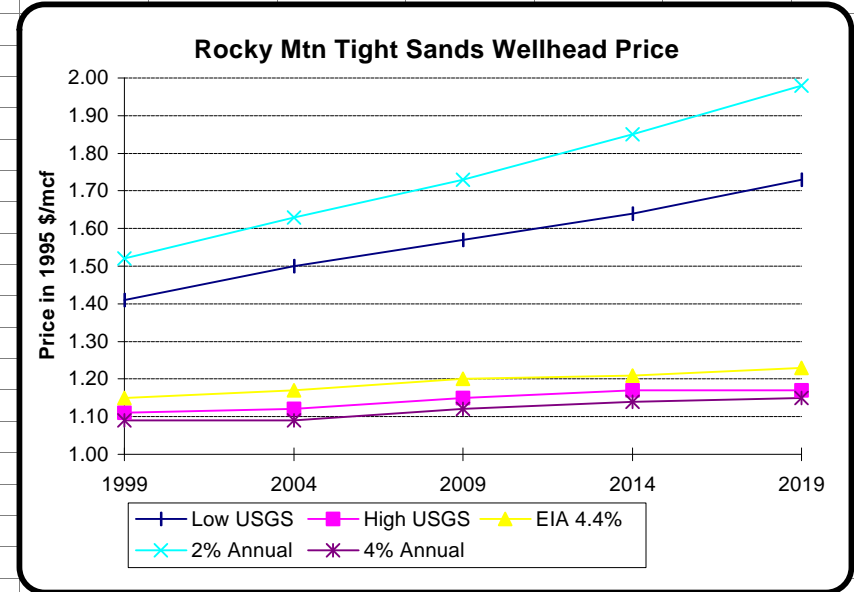


Rocky Mtns

Tight Sands Rocky Mtn Wellhead Price
by Reference Case

1995 \$/mcf

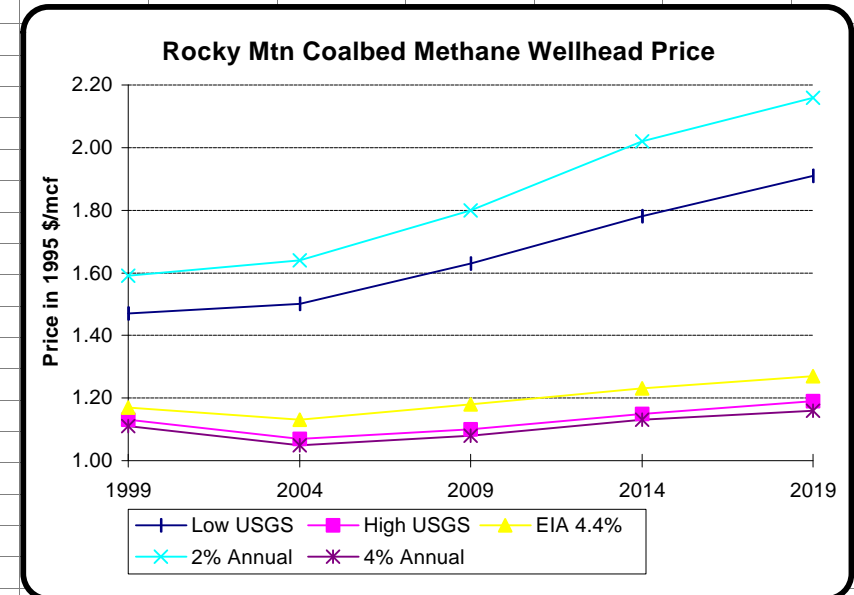
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.41	1.50	1.57	1.64	1.73	1.0%
High USGS	1.11	1.12	1.15	1.17	1.17	0.3%
EIA 4.4%	1.15	1.17	1.20	1.21	1.23	0.3%
2% Annual	1.52	1.63	1.73	1.85	1.98	1.3%
4% Annual	1.09	1.09	1.12	1.14	1.15	0.3%



Coalbed Methane Rocky Mtn Wellhead Price
by Reference Case

1995 \$/mcf

	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.47	1.50	1.63	1.78	1.91	1.3%
High USGS	1.13	1.07	1.10	1.15	1.19	0.3%
EIA 4.4%	1.17	1.13	1.18	1.23	1.27	0.4%
2% Annual	1.59	1.64	1.80	2.02	2.16	1.5%
4% Annual	1.11	1.05	1.08	1.13	1.16	0.2%



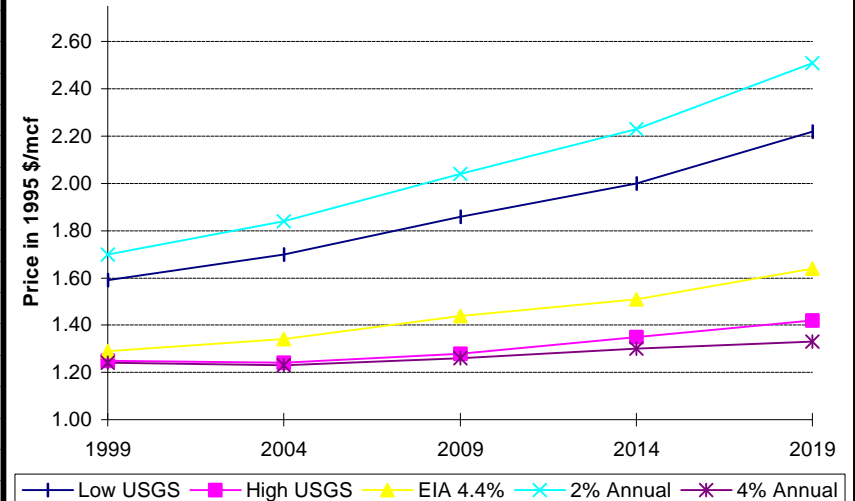
Rocky Mtns

Rocky Mtn to San Juan
by Reference Case

1995 \$/mcf

	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.59	1.70	1.86	2.00	2.22	1.7%
High USGS	1.25	1.24	1.28	1.35	1.42	0.6%
EIA 4.4%	1.29	1.34	1.44	1.51	1.64	1.2%
2% Annual	1.70	1.84	2.04	2.23	2.51	2.0%
4% Annual	1.24	1.23	1.26	1.30	1.33	0.4%

Rocky Mtn Delivery Price to the San Juan Basin

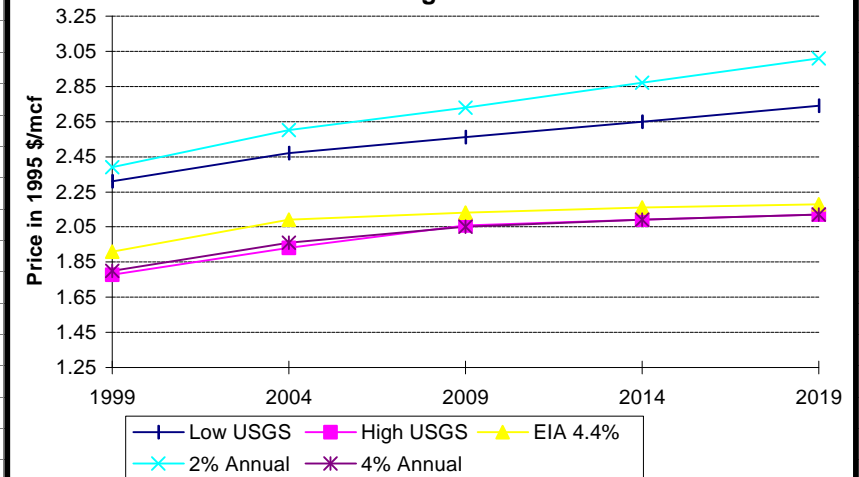


Rocky Mtn to WNC
by Reference Case

1995 \$/mcf

	1999	2004	2009	2014	2019	Growth Rate
Low USGS	2.31	2.47	2.56	2.65	2.74	0.9%
High USGS	1.78	1.93	2.06	2.09	2.12	0.9%
EIA 4.4%	1.91	2.09	2.13	2.16	2.18	0.7%
2% Annual	2.39	2.60	2.73	2.87	3.01	1.2%
4% Annual	1.80	1.96	2.05	2.09	2.12	0.8%

Rocky Mtn Delivery Price to the WNC Demand
Region



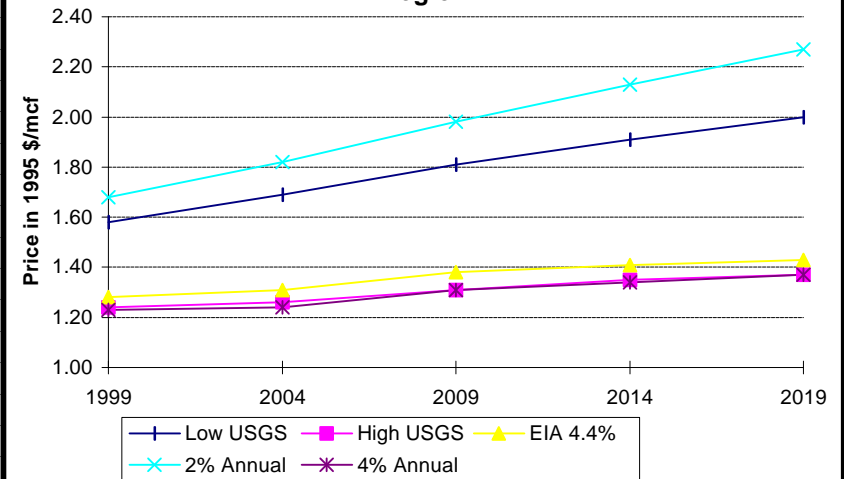
Rocky Mtns

Rocky Mtn to Rocky Mtn Demand
by Reference Case

1995 \$/mcf

	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.58	1.69	1.81	1.91	2.00	1.2%
High USGS	1.24	1.26	1.31	1.35	1.37	0.5%
EIA 4.4%	1.28	1.31	1.38	1.41	1.43	0.6%
2% Annual	1.68	1.82	1.98	2.13	2.27	1.5%
4% Annual	1.23	1.24	1.31	1.34	1.37	0.5%

Rocky Mtn Delivery Price to the Rocky Mtn Demand
Region

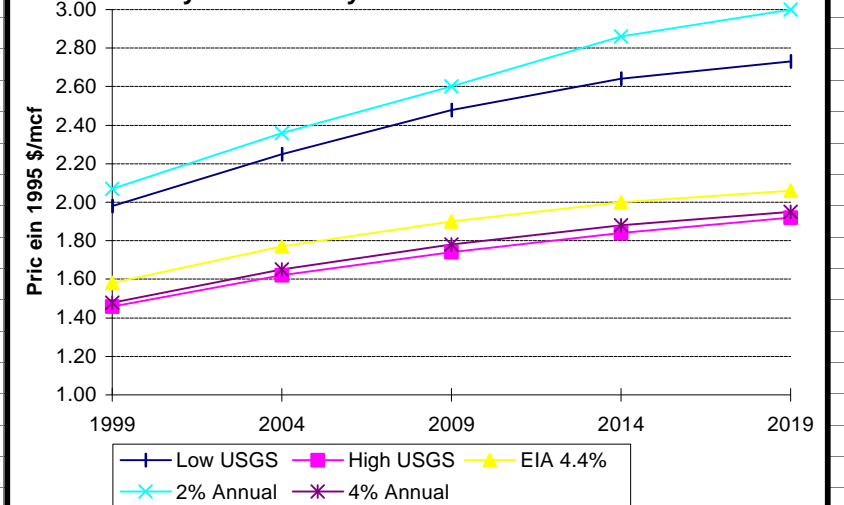


Rocky Mtns to Anadarko
by Reference Case

1995 \$/mcf

	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.98	2.25	2.48	2.64	2.73	1.6%
High USGS	1.46	1.62	1.74	1.84	1.92	1.4%
EIA 4.4%	1.58	1.77	1.90	2.00	2.06	1.3%
2% Annual	2.07	2.36	2.60	2.86	3.00	1.9%
4% Annual	1.48	1.65	1.78	1.88	1.95	1.4%

Rocky Mtn Delivery Price to the Anadarko Basin



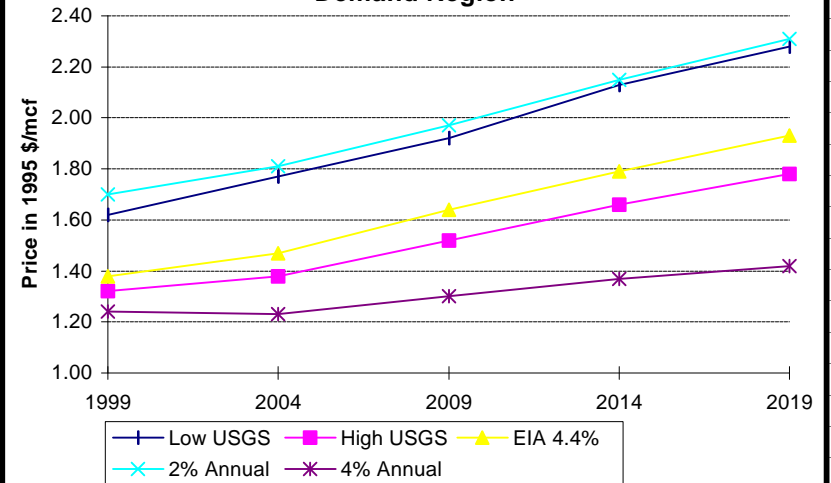
Rocky Mtns

Rocky Mtns to Pacific Northwest
by Reference Case

1995 \$/mcf

	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>	<u>Growth Rate</u>
Low USGS	1.62	1.77	1.92	2.13	2.28	1.7%
High USGS	1.32	1.38	1.52	1.66	1.78	1.5%
EIA 4.4%	1.38	1.47	1.64	1.79	1.93	1.7%
2% Annual	1.70	1.81	1.97	2.15	2.31	1.5%
4% Annual	1.24	1.23	1.30	1.37	1.42	0.7%

Rocky Mtn Delivery Price to the Pacific Northwest
Demand Region

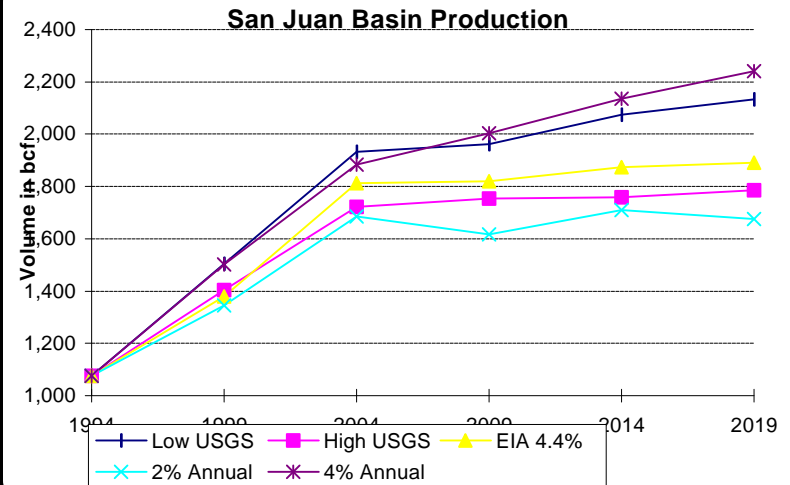


San Juan

San Juan Basin Production
by Reference Case

bcf

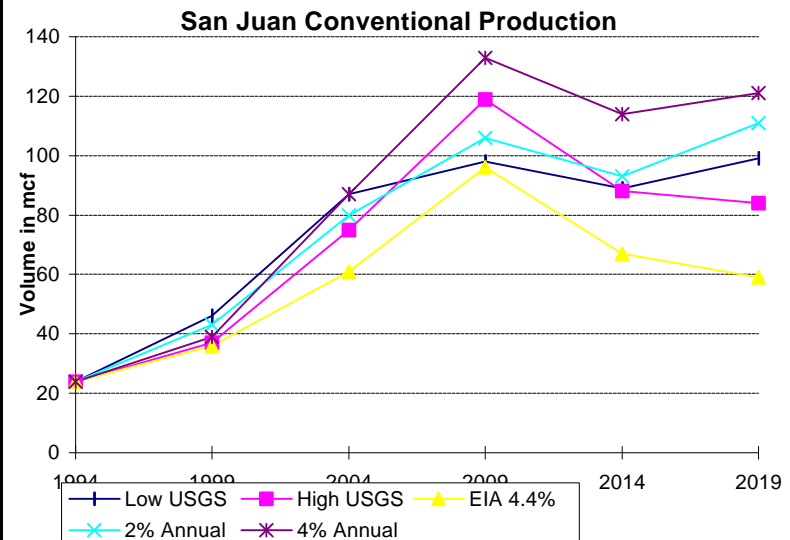
	1994	1999	2004	2009	2014	2019
Low USGS	1,075	1,504	1,932	1,961	2,075	2,134
High USGS	1,075	1,404	1,722	1,754	1,759	1,786
EIA 4.4%	1,075	1,380	1,812	1,819	1,875	1,892
2% Annual	1,075	1,345	1,685	1,617	1,710	1,675
4% Annual	1,075	1,501	1,883	2,003	2,136	2,242



San Juan Conventional Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	24	46	87	98	89	99
High USGS	24	37	75	119	88	84
EIA 4.4%	24	36	61	96	67	59
2% Annual	24	43	80	106	93	111
4% Annual	24	39	87	133	114	121



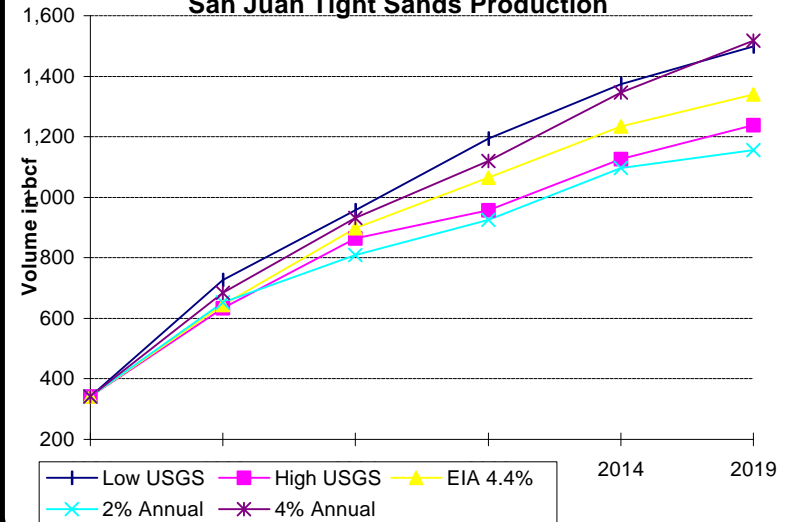
San Juan

San Juan Tight Sands Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	342	727	957	1,193	1,374	1,498
High USGS	342	634	864	958	1,126	1,238
EIA 4.4%	342	645	898	1,065	1,234	1,339
2% Annual	342	653	810	925	1,097	1,156
4% Annual	342	684	931	1,120	1,347	1,518

San Juan Tight Sands Production

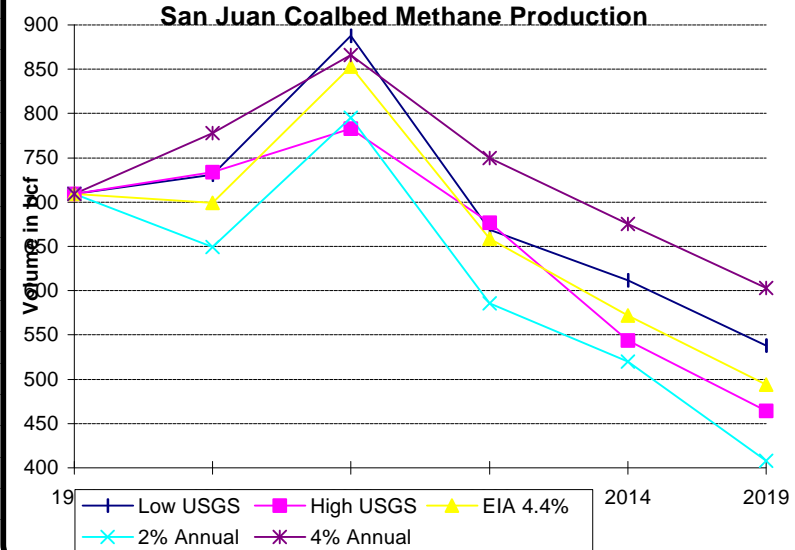


San Juan Basin Coalbed Methane Production
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	709	731	888	669	612	538
High USGS	709	734	783	677	544	464
EIA 4.4%	709	699	853	659	572	494
2% Annual	709	649	795	586	520	408
4% Annual	709	778	866	750	675	603

San Juan Coalbed Methane Production



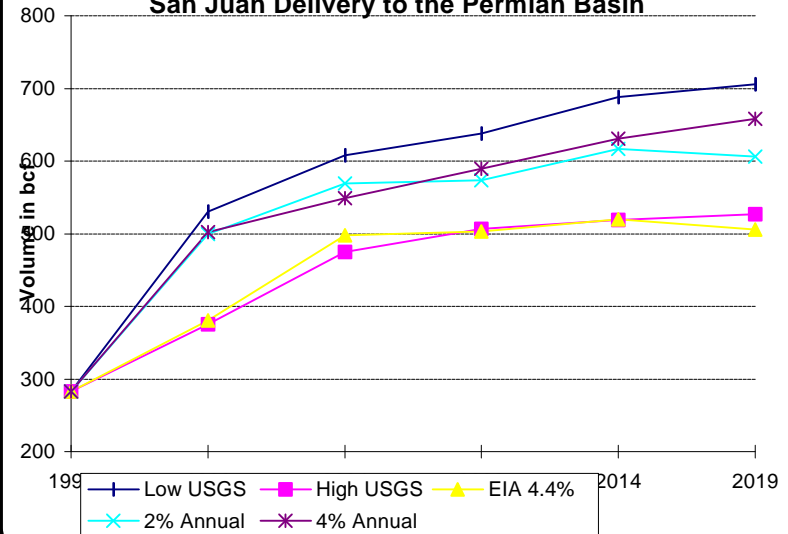
San Juan

San Juan Delivery to Permian
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	283	530	608	638	688	706
High USGS	283	375	475	507	519	527
EIA 4.4%	283	381	498	503	520	506
2% Annual	283	500	569	574	617	606
4% Annual	283	502	549	589	631	658

San Juan Delivery to the Permian Basin

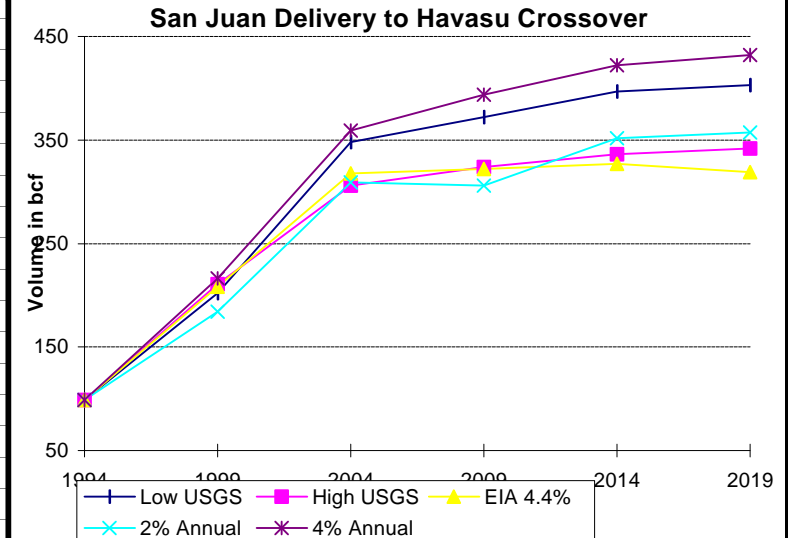


San Juan Delivery to Havasu X-Over
by Reference Case

bcf

	1994	1999	2004	2009	2014	2019
Low USGS	99	202	348	372	397	403
High USGS	99	211	306	324	336	342
EIA 4.4%	99	208	318	322	327	319
2% Annual	99	184	309	306	352	357
4% Annual	99	216	359	394	422	432

San Juan Delivery to Havasu Crossover



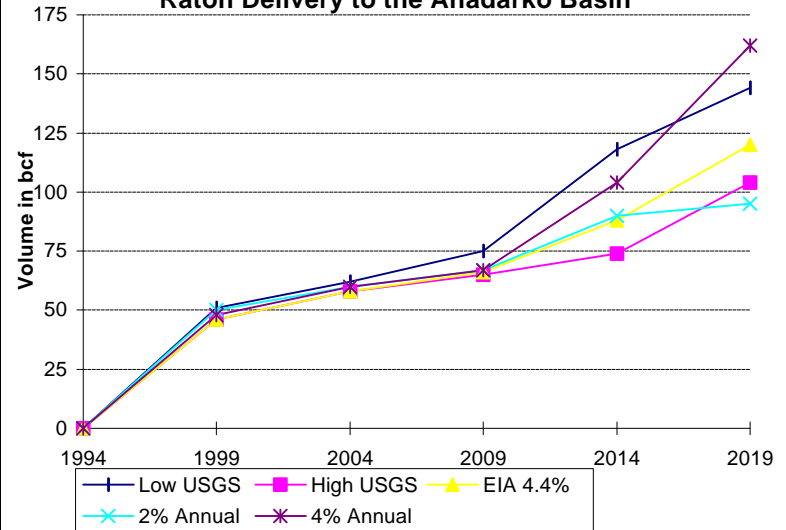
San Juan

Raton Delivery to Anadarko
by Reference Case

bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	0	51	62	75	118	144
High USGS	0	46	58	65	74	104
EIA 4.4%	0	46	58	66	88	120
2% Annual	0	50	60	67	90	95
4% Annual	0	48	60	67	104	162

Raton Delivery to the Anadarko Basin

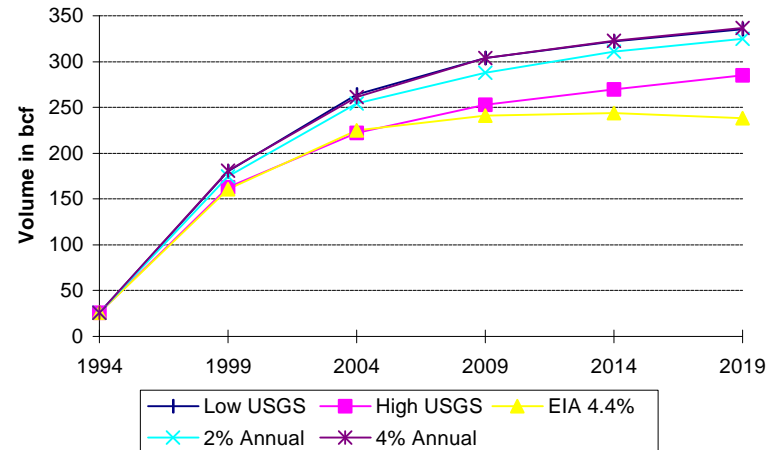


San Juan Delivery to SW Desert
by Reference Case

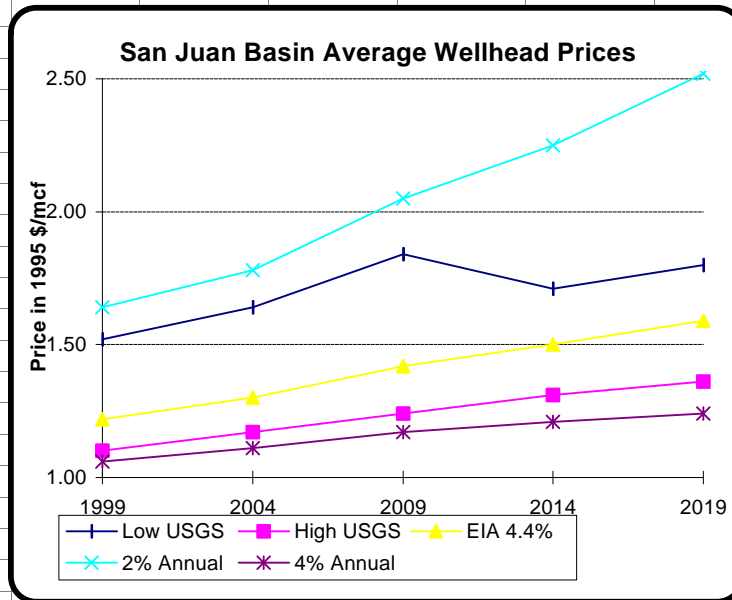
bcf

	<u>1994</u>	<u>1999</u>	<u>2004</u>	<u>2009</u>	<u>2014</u>	<u>2019</u>
Low USGS	26	180	264	304	322	335
High USGS	26	163	222	253	270	285
EIA 4.4%	26	161	225	241	244	238
2% Annual	26	175	254	288	311	325
4% Annual	26	181	261	304	323	337

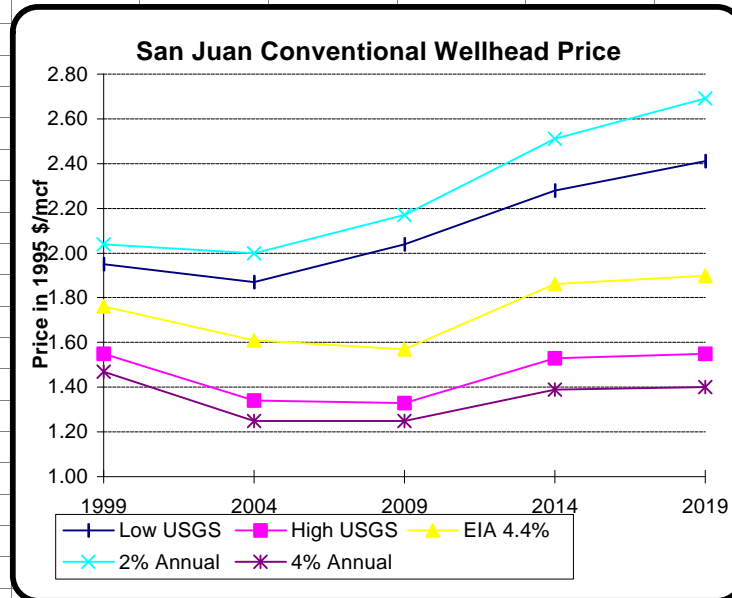
San Juan Delivery to the SW Desert Demand Region



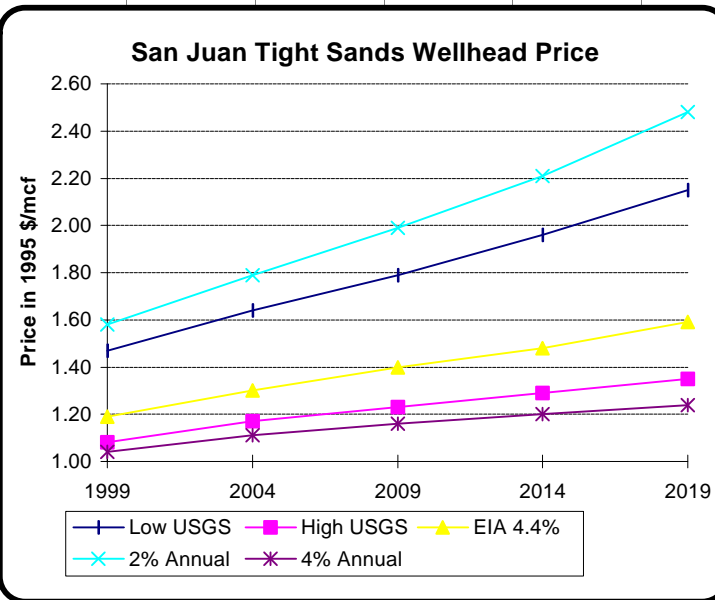
San Juan Basin Production by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.52	1.64	1.84	1.71	1.80	0.8%
High USGS	1.10	1.17	1.24	1.31	1.36	1.1%
EIA 4.4%	1.22	1.30	1.42	1.50	1.59	1.3%
2% Annual	1.64	1.78	2.05	2.25	2.52	2.2%
4% Annual	1.06	1.11	1.17	1.21	1.24	0.8%



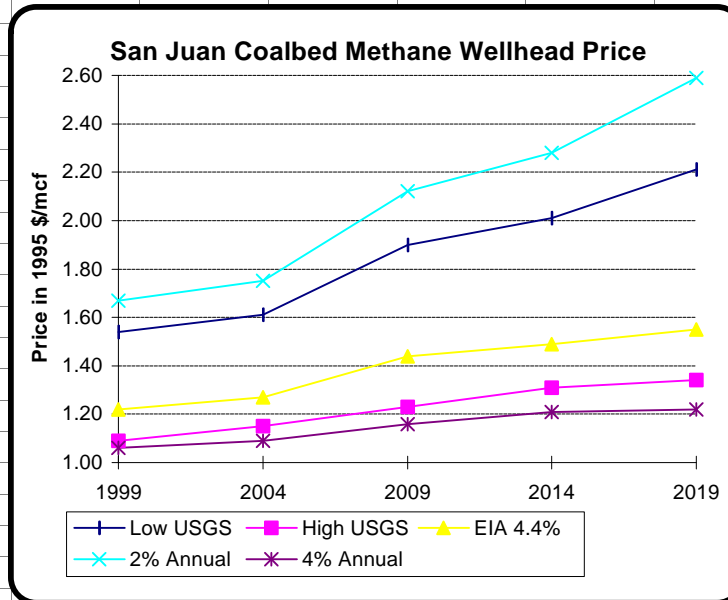
San Juan Conventional Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.95	1.87	2.04	2.28	2.41	1.1%
High USGS	1.55	1.34	1.33	1.53	1.55	0.0%
EIA 4.4%	1.76	1.61	1.57	1.86	1.90	0.4%
2% Annual	2.04	2.00	2.17	2.51	2.69	1.4%
4% Annual	1.47	1.25	1.25	1.39	1.40	-0.2%



San Juan Tight Sands Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.47	1.64	1.79	1.96	2.15	1.9%
High USGS	1.08	1.17	1.23	1.29	1.35	1.1%
EIA 4.4%	1.19	1.30	1.40	1.48	1.59	1.5%
2% Annual	1.58	1.79	1.99	2.21	2.48	2.3%
4% Annual	1.04	1.11	1.16	1.20	1.24	0.9%

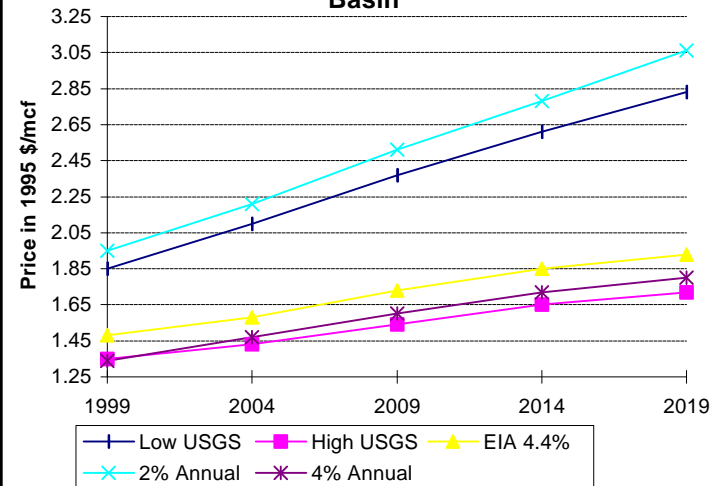


San Juan Coalbed Methane Wellhead Price by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.54	1.61	1.90	2.01	2.21	1.8%
High USGS	1.09	1.15	1.23	1.31	1.34	1.0%
EIA 4.4%	1.22	1.27	1.44	1.49	1.55	1.2%
2% Annual	1.67	1.75	2.12	2.28	2.59	2.2%
4% Annual	1.06	1.09	1.16	1.21	1.22	0.7%



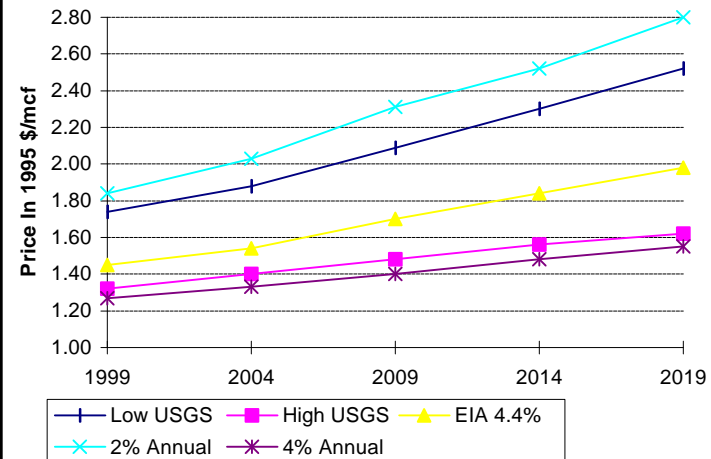
San Juan Delivery Price to Permian by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.85	2.10	2.37	2.61	2.83	2.1%
High USGS	1.35	1.43	1.54	1.65	1.72	1.2%
EIA 4.4%	1.48	1.58	1.73	1.85	1.93	1.3%
2% Annual	1.95	2.21	2.51	2.78	3.06	2.3%
4% Annual	1.34	1.47	1.60	1.72	1.80	1.5%

**San Juan Delivery Price to the Permian
Basin**



San Juan Delivery to Havasu X-Over by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.74	1.88	2.09	2.30	2.52	1.9%
High USGS	1.32	1.40	1.48	1.56	1.62	1.0%
EIA 4.4%	1.45	1.54	1.70	1.84	1.98	1.6%
2% Annual	1.84	2.03	2.31	2.52	2.80	2.1%
4% Annual	1.27	1.33	1.40	1.48	1.55	1.0%

**San Juan Delivery Price to the Havasu
Crossover**



San Juan

Raton Delivery to Anadarko by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	2.15	2.47	2.70	2.83	3.01	1.7%
High USGS	1.58	1.76	1.90	2.00	2.02	1.2%
EIA 4.4%	1.72	1.94	2.07	2.14	2.17	1.2%
2% Annual	2.25	2.59	2.85	3.08	3.31	1.9%
4% Annual	1.60	1.80	1.94	1.98	2.01	1.1%

San Juan Delivery to SW Desert by Reference Case						
1995 \$/mcf						
	1999	2004	2009	2014	2019	Growth Rate
Low USGS	1.82	2.00	2.22	2.42	2.66	1.9%
High USGS	1.40	1.50	1.59	1.67	1.73	1.1%
EIA 4.4%	1.53	1.64	1.81	1.96	2.10	1.6%
2% Annual	1.93	2.15	2.44	2.65	2.94	2.1%
4% Annual	1.34	1.44	1.50	1.59	1.67	1.1%

